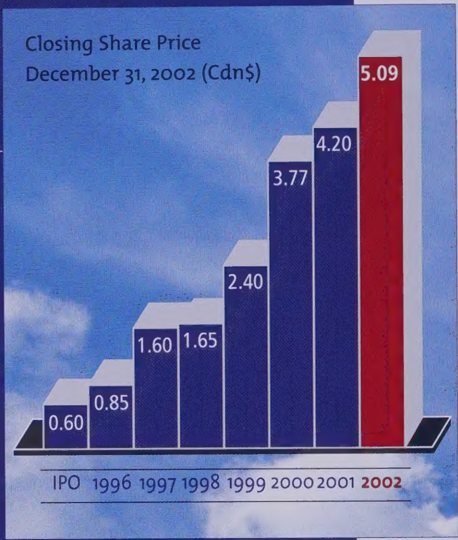
ANNUAL REPORT 2002

COMPTON
PETROLEUM CORPORATION

PROFILE

Compton Petroleum Corporation is a Calgary-based independent public company actively engaged in the exploration, development and production of natural gas, natural gas liquids and crude oil in the Western Canada Sedimentary Basin. The Company's capital stock trades on the Toronto Stock Exchange (TSX) under the symbol CMT, and is included in both the S&P/TSX Composite Index and the TSX Mid-Cap Index.

Compton commenced operations in 1993 with $1 million of share capital, a small dedicated technical team and a large seismic data base. The objective was to build a company capable of long-term sustained growth with a primary focus on natural gas through internal full-cycle exploration, complemented by strategic acquisitions. Compton's focus and strategy have remained unchanged since inception. Nine years later, in 2002, the Company attained average production of 25,137 boe per day (6:1), long-life established reserves of 103.5 million boe (6:1), control of more than 1,400 sections of undeveloped land and a total asset value in excess of $1 billion.



ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders will be held on Tuesday, June 3, 2003 at 3:30 p.m. in The Historical Ballroom, Calgary Chamber of Commerce, 517-Centre Street South, Calgary, Alberta, Canada.

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COMPTON'S STRONG 2002 PERFORMANCE

DRILLING SUCCESS

90%

- 73% success rate from 1996 to 2002.
- Average well depth 1,790 metres (5,870 feet).

ESTABLISHED RESERVES INCREASE

24%

- Total established reserves – 104 million boe.
- 80% natural gas-weighted.

FINDING & DEVELOPMENT COSTS

$5.35

PER BOE ESTABLISHED

- $7.92/boe proven – among the best in the industry.
- 3 year average $8.84/boe proven, $7.15/boe established.
- 5 year average $7.59/boe proven, $6.30/boe established.

UNDEVELOPED SECTIONS OF LAND

1,400

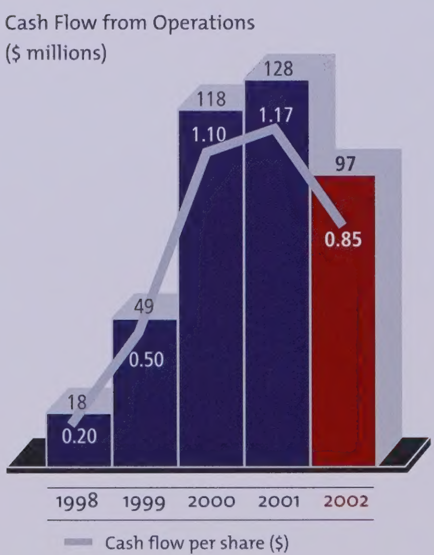
- 5+ years of drilling opportunities.
- High working interests, concentrated in core areas.

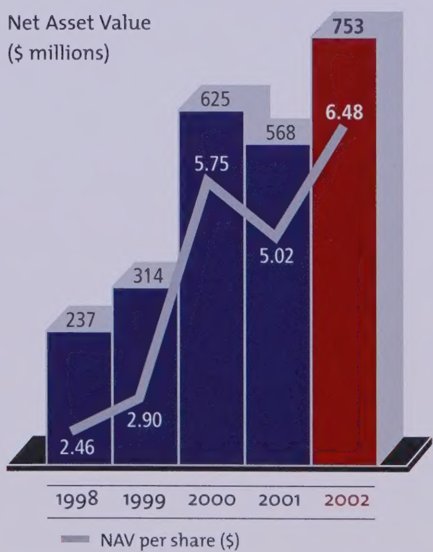
POSITIONED FOR THE FUTURE

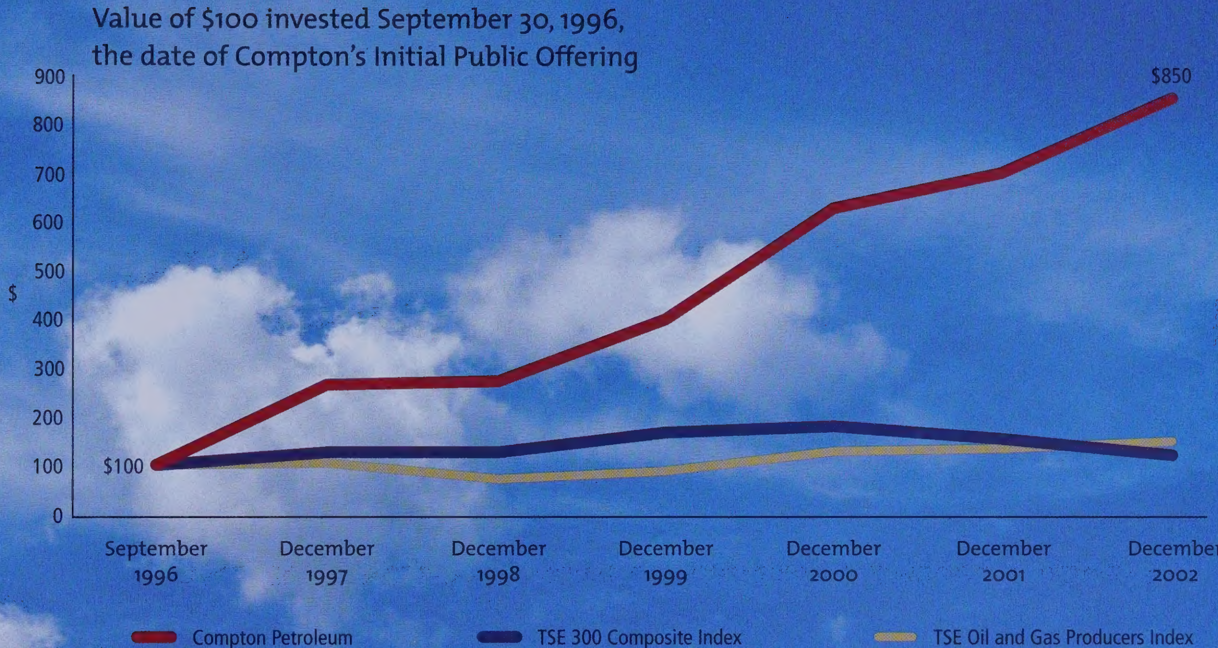
FINANCIAL HIGHLIGHTS

Compton achieved strong financial performance in 2002. Compton realized $219.8 million in petroleum and natural gas revenue. Cash flow and net earnings benefited from increased production volumes; however, the results were impacted by lower realized commodity prices. Cash flow from operations in 2002 was $96.5 million ($0.85 per share basic) while net earnings for the year totalled $18.8 million ($0.17 per share basic). Net asset value as at December 31, 2002 was $753.4 million ($6.48 per share), based upon established reserves (escalated dollar pricing) discounted at 10 percent.

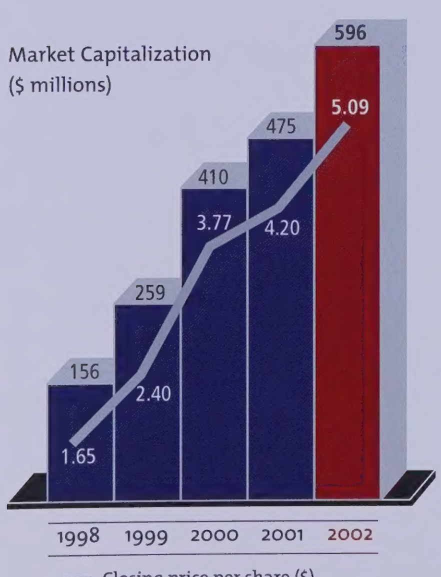
($000s, except where noted)	**2002**	2001	2000
Total revenue	**219,787**	244,970	213,376
Cash flow from operations	**96,518**	128,334	117,533
Per share: – basic ($)	**0.85**	1.17	1.10
– diluted ($)	**0.82**	1.12	1.06
Net earnings	**18,798**	55,636	40,059
Per share: – basic ($)	**0.17**	0.51	0.37
– diluted ($)	**0.16**	0.48	0.36
Capital expenditures	**155,108**	190,467	118,472
Corporate debt, net	**268,621**	208,299	153,440
Shareholders' equity	**245,799**	217,860	157,796

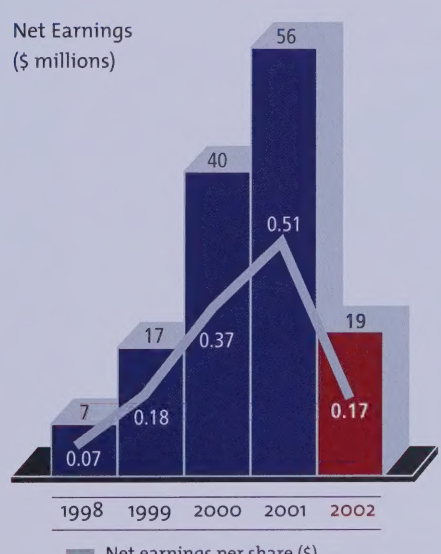






Shareholders who invested $100 in Compton in 1996 saw a value of $850 at the end of 2002.
Liquidity – average daily trading volume exceeds 400,000 shares per day.



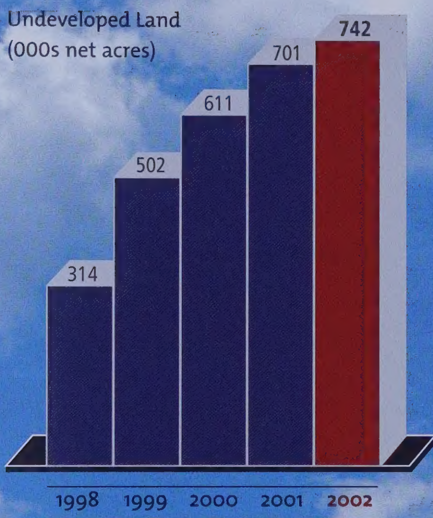


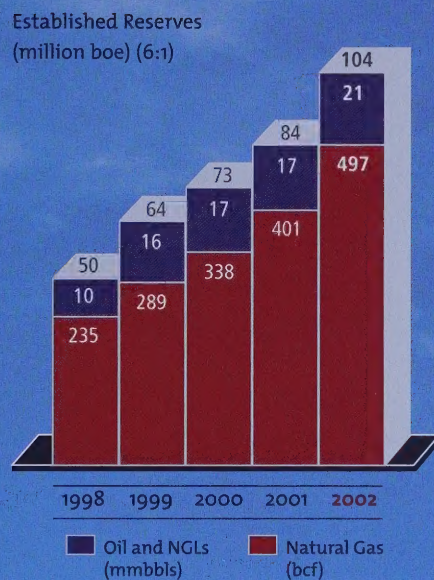
OPERATING HIGHLIGHTS

Compton has assembled a very large prospective land base of more than one million acres, concentrated in core areas. In 2002, 87 wells were drilled at an overall success rate of 90 percent. Production continued to increase, with an annual average of 25,137 boe per day in 2002.

The Company's reserve base is strong with total established reserves at year-end of 103.5 million boe. Natural gas reserves, comprising 80 percent of established reserves, were 497.5 billion cubic feet. Reserve additions for 2002 were achieved at an all-in finding and development cost of $7.92 per boe on a proven basis and $5.35 per boe established. Five-year average finding and development costs are $7.59 per boe proven and $6.30 per boe established.

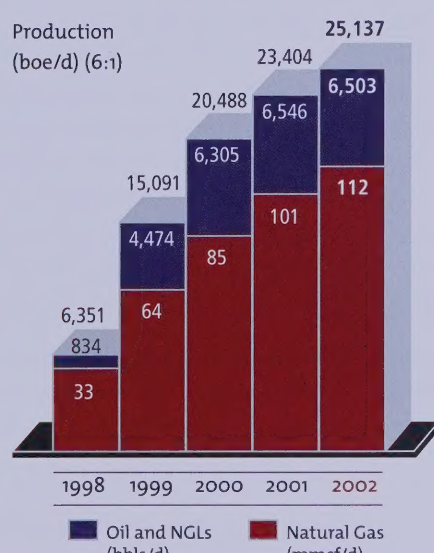
(6:1 boe conversion)	**2002**	2001	2000
Average daily production:			
Natural gas (mmcf/d)	**111.8**	101.1	85.1
Liquids (light oil & ngls) (bbls/d)	**6,503**	6,546	6,305
Total oil equivalent (boe/d)	**25,137**	23,404	20,488
Average pricing:			
Natural gas ($/mcf)	**3.67**	4.77	4.55
Liquids ($/bbl)	**29.43**	28.83	31.29
Total oil equivalent ($/boe)	**23.95**	28.68	28.53
Field operating netback ($/boe)	**13.82**	17.42	18.34
Cash flow netback ($/boe)	**10.39**	15.01	15.72
Undeveloped land:			
Gross acres	**1,042,923**	962,259	763,503
Net acres	**742,465**	700,695	610,640
Average working interest	**71%**	73%	77%
Reserves:			
Proven oil equivalent (mboe)	**82,156**	71,754	61,014
Established oil equivalent (mboe)	**103,501**	83,675	72,969



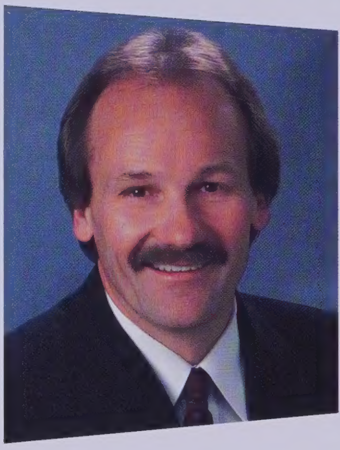


"We strongly believe we can deliver a superior return to our shareholders by developing our significant undeveloped land base through drilling opportunities."

Ernie Sapieha
President and
Chief Executive Officer



LETTER TO SHAREHOLDERS



Vi·sion vɪʒ(ə)n 1. *noun* a vivid mental image 2. *noun* foresight; good judgement in planning and strategy.

TO OUR SHAREHOLDERS:

From the outset, Compton's vision has been to build a significant exploration and development company, capable of sustaining long-term growth while creating superior and lasting shareholder value.

In pursuing this vision we have consistently applied a clear and simple strategy:

- Focus on long-life, low-decline natural gas targets;
- Develop strong technical teams, expertise and governance;
- Internal generation of prospects;
- Create dominant core area land positions with high working interests;
- Control of infrastructure and operatorship; and
- Full-cycle exploration complemented by strategic acquisitions.

WHAT HAVE OUR VISION AND STRATEGY ACCOMPLISHED?

Simply stated, we have created an intermediate exploration and production company with solid reserves and an undeveloped land base capable of generating growth for years to come. Adherence to our focused strategy has resulted in Compton achieving mid-cap status with an asset value in excess of $1 billion.

Approximately 75 percent of our production and 80 percent of our reserves are natural gas with a proven reserve life index of nine years. Our reserves are solid and have grown from 12.1 million boe at December 31, 1996 to 103.5 million boe at December 31, 2002. Eighty percent of Compton's reserves are classified as proven, of which only

"Compton's total asset value exceeds $1 billion."

seven percent are proven undeveloped. During the past four years, 77 percent of our reserve additions have been generated through the drill bit.

Compton has developed outstanding geological, geophysical, engineering and operational expertise in deep basin natural gas and uphole targets. In 2002, we drilled 87 wells with an overall success rate of 90 percent. Our finding and development costs are among the best in the industry. Reserve additions for 2002 were achieved at an all-in cost of $7.92 per boe on a proven basis and $5.35 per boe on an established basis. Based on a five-year average, which is more reflective of full-cycle exploration, finding and development costs are $7.59 per boe proven and $6.30 per boe established.

Compton has assembled a very large, prospective undeveloped land base of more than one million acres, concentrated in our core areas. We have an average 71 percent working interest in these properties and have identified a minimum of five years of internally-generated drilling prospects.

Compton has built a very strong reserve base and has achieved consistent production growth. Production has steadily increased from 1,025 boe per day in 1996 to 25,137 boe per day in 2002.

Shareholders who invested $100 in Compton in 1996 saw a value of approximately $850 at the end of 2002. We are confident our future is even brighter.

SO, YOU ASK WHY COMPTON?

During the past few years, the oil and gas industry in Western Canada has seen significant change. The intermediate producers have all but disappeared. Some have been acquired by larger companies and others have converted to royalty trusts. Some companies realized their best alternative to maximize shareholder value was to sell into a strong market. Others believed that distributing cash from operations would result in a greater benefit to shareholders than reinvesting cash flow in exploration and development.

At Compton, we have considered all alternatives. We believe that given the wealth of opportunities open to us, we can achieve superior value for our shareholders by staying the course. We have built a company that has a solid foundation and is rich in future opportunities.

We strongly believe we can deliver a superior return to our shareholders by developing our significant undeveloped land base through drilling. We have more than five years of opportunities from this large, natural gas-prone land base, and Compton has developed the necessary expertise in numerous pay zones, avoiding dependence on any one reservoir.

Compton can double natural gas production from its existing land base. The outlook for commodity prices, particularly natural gas, remains positive and will only compound the impact of future production increases. Compton's extensive experience and technical knowledge with deep, tight natural gas and uphole reservoirs gives the Company a competitive advantage. We are well positioned to capitalize on our technical expertise within existing core areas as well as in connection with new opportunities.

"Our finding and development costs are among the best in the industry."

Left to right: Derek Longfield, Vice President, Engineering; Norm Knecht, Vice President, Finance and Chief Financial Officer; Marc Junghans, Vice President, Exploration; Theresa Kosek, Manager, Accounting; Greg Shpytkovsky, Manager, Drilling; Gary Follensbee, Manager, Joint Ventures and Special Projects.

Additionally, Compton can significantly increase corporate reserves from its existing land base. We are one of the few companies that has continued to add significant reserves through the drill bit. This potential growth comes with a track record of one of the best long-term finding and development costs in the industry.

Strategic acquisitions in our core areas will continue to remain a part of our strategy. We have been very successful in all of our past acquisitions. Compton has demonstrated we can grow successfully through acquisitions as well as the drill bit. Our current capital structure provides the financial flexibility to pursue opportunities as they arise.

As I have previously stated, stewardship and governance of a successful and growing oil and gas company is very challenging and complex. It requires experience and understanding of the business and the risks. One of Compton's key reasons for success and consistent results is the contribution made by an outstanding Board of Directors and the high quality corporate governance they provide. Our well respected Board has a complementary wealth of large company experience in all aspects of the oil and gas industry. Compton's Board is comprised of five members, four of whom are independent, with all directors holding a significant personal investment in Compton. The very challenging Board is an outstanding asset for Compton, as its members continually look out for the best interests of all shareholders.

FURTHER WORK TO BE DONE

Although we are proud of our accomplishments to date, there is always further work to be done. Compton's largest core area, Southern Alberta, with more than 1,000 sections of land just south of Calgary, continues to improve with time. We have experienced very positive drilling results, generating high quality reserves and production. Our success has pushed our processing and gathering facilities to operate at maximum capacity. These temporary facility constraints are problematic, but we are working to expand our facilities and to add needed pipeline capacity by the end of the third quarter of 2003.

Compton's Hooker play, which is only one-third developed, has yielded 243 bcf of established reserves to date. We are well on our way to exceeding our estimate of one-half tcf of net reserves from this play. In addition to Hooker, we are also realizing very positive results from our deep Crossfield gas play at Mazeppa and our medium-depth gas play at Gladys and Brant. Our exploration plays at Tsuu T'ina, Callum and Aphrodite are very promising in their early stages.

Elsewhere in Alberta, we are experiencing very good drilling results in the Peace River Arch and Central Alberta. The Arch area offers multi-zone potential for both exploration and development opportunities. We are applying the same

Left to right: Murray Stodalka, Vice President, Operations; Wade Mrochuk, Manager, Production; Terry Mah, Senior Manager, Acquisitions; Bill Leonard, Manager, Human Resources; Kim Davies, Vice President, New Ventures; Tim Millar, Vice President and General Counsel; Corinna King, Manager, Finance.

strategy used in Southern Alberta to the Arch. In Central Alberta, Compton has excellent exploitation and development drilling opportunities, which are an important balance to the Company's exploration programs in other core areas.

For 2003, Compton has budgeted more than 150 wells, two-thirds of which are in Southern Alberta and one-third in our other core areas.

THE BEST IS YET TO COME

We believe that Compton is very well positioned for the future. We have a strong reserve and production base concentrated in core areas. We have enhanced our expertise in exploring for and developing deep, tight gas targets. Compton has continued to add to its large, prospective gas-prone land base. As a result, we are very excited about our future potential.

Continued high demand for natural gas and increased gas prices bode well for Compton and its shareholders. Colder weather in Eastern Canada and the Northern United States, the lack of alternate fuel sources and high crude oil prices continue to keep demand strong and prices above average for natural gas. Recent world events leading to further uncertainty in energy supply also continue to contribute to higher prices. Presently, there is no immediate end in sight to higher gas prices and low supply. We believe the new NYMEX base is US$4.00 per mcf.

Consistent growth through exploration is difficult. The development of natural gas reserves takes a long time – it's not for the faint of heart. However, as our finding and development costs over the last three years have demonstrated, there are great returns and value to be derived from drilling. Compton will continue to focus on the fundamentals and our strategy.

Implementation of our strategy has been precise and meticulous from inception. With the resolution of temporary processing constraints, Compton will be well positioned for continued sustainable growth and will continue to create long-term value for its shareholders. Beyond 2003, Compton will benefit from the previous years of methodical planning and hard work. The best is yet to come.

Sincerely,

Ernie Sapieha,
President and Chief Executive Officer

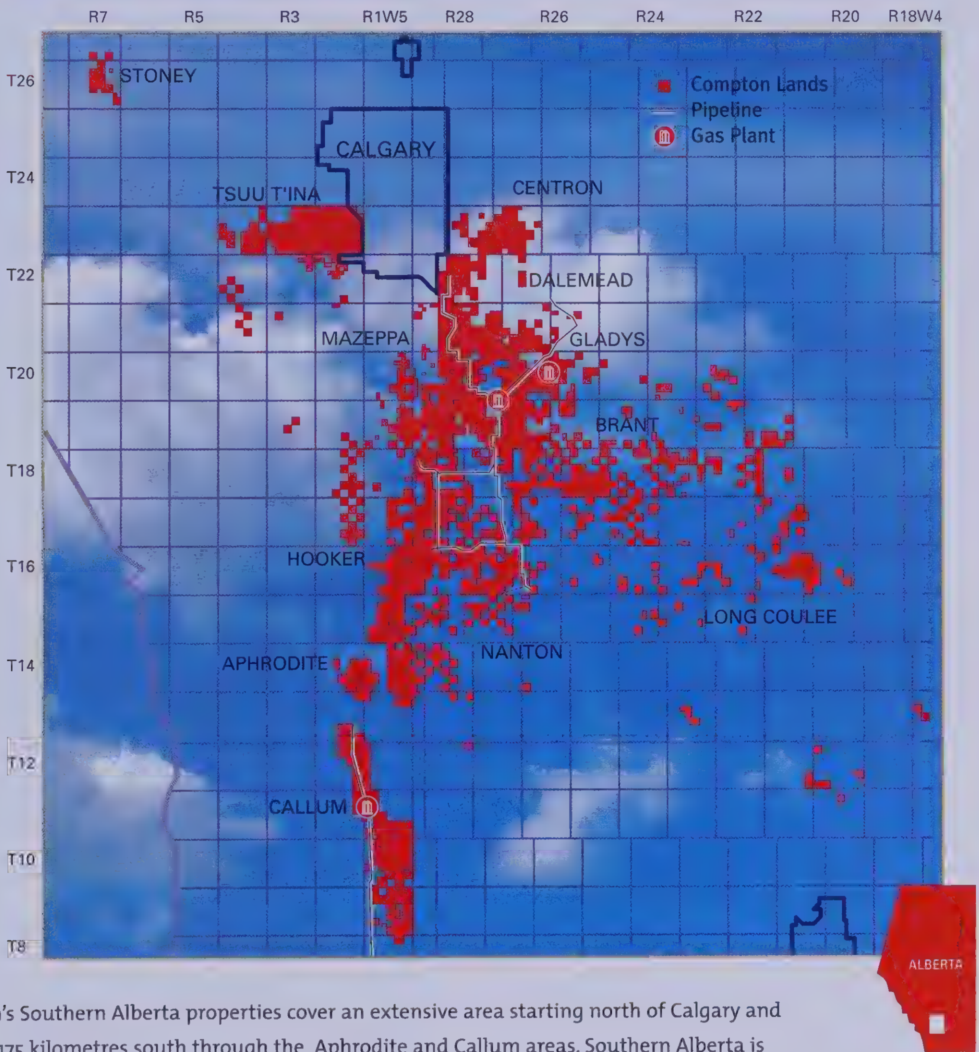
"The best is yet to come..."

OPERATIONS REVIEW

Compton's strategy and success revolve around its core areas. In 2002, Compton continued to focus on the exploration and development of internally-generated prospects within the Western Canada Sedimentary Basin. A variety of plays, from long-term exploration and development prospects in Southern Alberta to mature, light oil producing areas in Central Alberta and the Peace River Arch, provide a balanced risk profile.

Compton operates approximately 88 percent of its existing production and has a 71 percent average working interest in its undeveloped lands. This allows the Company to exercise discretion in determining the timing and methodology of its ongoing exploration and development programs. The Company will continue to consolidate its position in its core operating areas to maximize operating efficiencies and maintain control over ongoing capital programs.

SOUTHERN ALBERTA



Compton's Southern Alberta properties cover an extensive area starting north of Calgary and running 175 kilometres south through the Aphrodite and Callum areas. Southern Alberta is prospective for multi-zone natural gas, including shallower Belly River gas, deeper tight Basal Quartz gas and Wabamun Crossfield gas. Compton's technical expertise and experience with deep, tight zones provide a strategic advantage in this area.

An aggressive exploration and development program has created more than a five-year inventory of drilling opportunities. The Company holds more than 740 (583 net) sections of undeveloped land in Southern Alberta, with an average working interest of 77 percent.

Southern Alberta was Compton's primary focus in 2002, representing approximately 60 percent of expenditures and 55 percent of production from several successful plays. Within Southern Alberta, Compton's primary play is a tight, lower Cretaceous Basal Quartz sandstone through the Hooker area.

HOOKER

The Company's deep, tight natural gas play at Hooker is centred approximately 80 kilometres south of Calgary. Compton holds over 200 sections (130,000 acres) of land on the play at an average working interest of 70 percent. The large, long-life reserve base in the Lower Cretaceous Basal Quartz sandstone is characterized by liquids-rich natural gas reserves. Well depths in the Hooker play are typically 2,400-3,400 metres, almost twice the average well depth in Alberta. Successful wells, which pay out in less than six months at current natural gas prices, have a reserve life index exceeding 10 years.

The Hooker play covers four townships on which Compton had booked net reserves of 243 billion cubic feet of natural gas at year-end 2002. The play has the potential to grow to nine townships and a minimum of 500 billion cubic feet of natural gas net to Compton.

In 2002, the Company concentrated on continuing to develop the Basin-centred tight natural gas play. The Company acquired 3-D seismic over 70 square kilometres resulting in numerous drilling locations and completed a 3-D seismic program to define additional locations on the play extension. Compton drilled 15 development wells and 10 exploratory wells in the Lower Cretaceous Basal Quartz sand with an 88 percent success rate. Exploratory activity expanded the play to the north and south. To the north, a successful exploration well extended the play 13 kilometres from established Hooker production.

Several wells encountered net pay exceeding 15 metres. To maximize reserves, Compton obtained regulatory approval to reduce well spacing to two wells per section on 26 sections of land in the heart of the play. The 10 infill development wells drilled in 2002 keyed off the initial well and proved to be either superior to or equal to the initial well in the section.

The increase in production from Hooker resulted in Compton's gathering and compression infrastructure reaching its capacity of 40 mmcf of natural gas per day. This temporary bottleneck was relieved by adding compression in early November and expanding the pipeline in December. The Company also purchased a 50 percent working interest in the Callum natural gas plant, which is capable of processing 30 mmcf of natural gas per day and is strategically located to handle new natural gas from the Aphrodite area. By the end of the third quarter of 2003, Compton intends to have further infrastructure in place, including a pipeline from Aphrodite to Callum, and an expansion of the Mazeppa natural gas plant that will add capacity of 30 mmcf of natural gas per day.

Compton plans to drill 23 wells on the Hooker Basal Quartz trend in 2003. Compton is also successfully pursuing development of zones uphole of the Basal Quartz in Hooker.

CENTRON/GLADYS/BRANT/MEDALLION

Located to the east of Hooker, the Centron-Medallion area offers medium-depth natural gas in multi-layered sandstones. The Company holds an extensive undeveloped land position of more than 150 sections at working interests ranging from 50-100 percent. This area offers a large inventory of drill-ready prospects in low-risk, low-decline sandstones. Compton drilled 26 wells in the Belly River formation in 2002 with a success rate of 96 percent. By year-end 2002, the Company had tied in 24 wells to add production of 15.7 mmcf of natural gas per day.

Based on these encouraging results, the Belly River play will be a focus of 2003 activity. Purchased seismic, together with 32 kilometres of new 2-D data, will set up prospects on individual Belly River sands and deeper, less explored zones. The Company plans 66 wells to test the Belly River and deeper targets in 2003.

MAZEPPA

The Okotoks-Mazeppa field holds great exploitation potential. It has been on production for several decades but still holds over 100 billion cubic feet of sales gas reserves in the Okotoks Wabamun B pool. In 2002, Compton successfully drilled a horizontal well in the south end of the pool. In 2003, the Company plans to drill four extended-reach horizontal wells targeting the best reservoir quality in order to accelerate depletion of the pool. This project is scheduled to coincide with the expansion of production facilities in 2003.

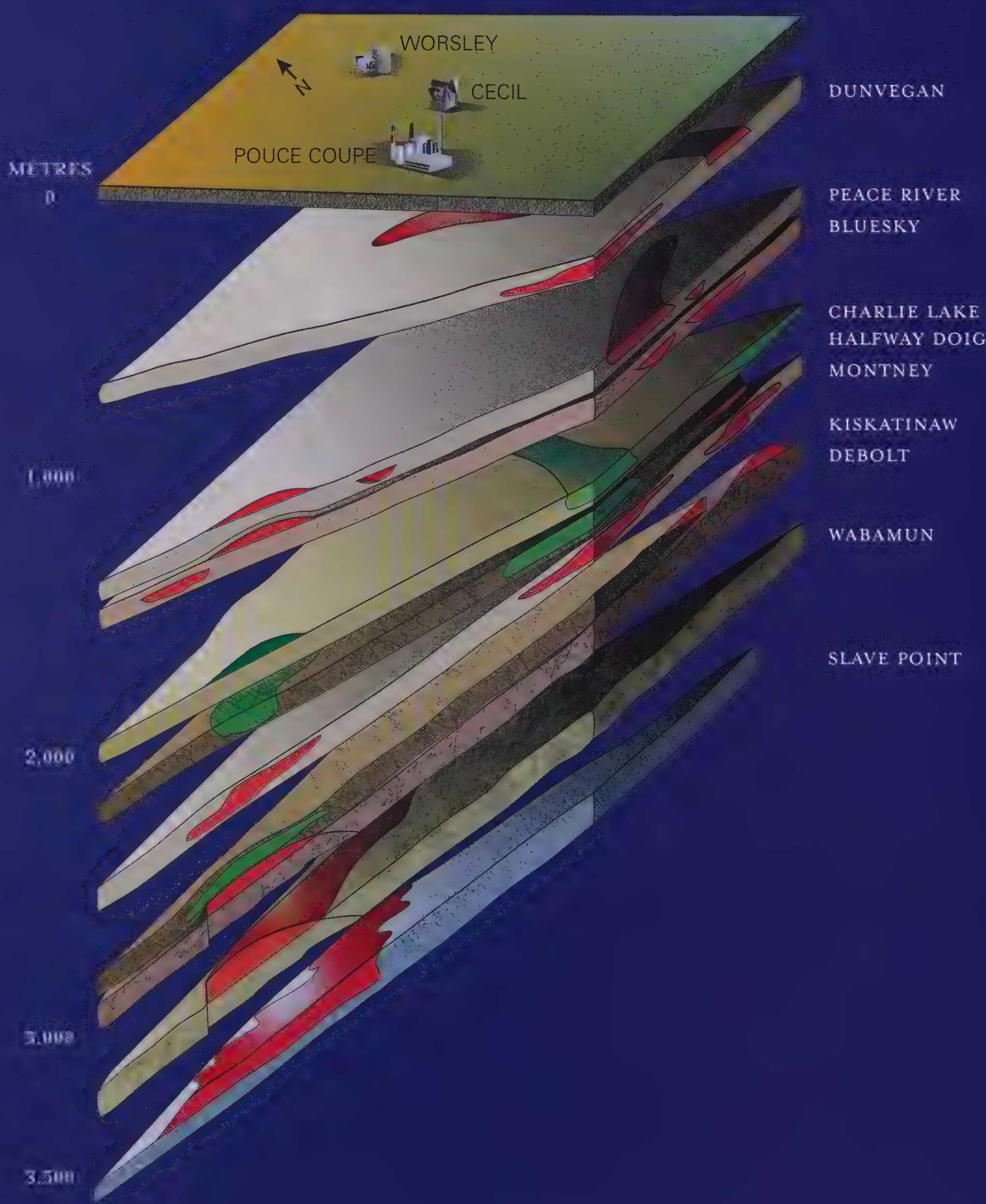
CALLUM

In October 2002, Compton acquired a 50 percent working interest and operatorship in 97 sections of undeveloped land at Callum. This acquisition added lands prospective for thrust-repeated Belly River natural gas sands, existing production of 1.0 mmcf of natural gas per day and access to a gas plant with capacity of 30 mmcf per day. The Callum natural gas plant is strategic to Compton because it can handle Foothills Belly River production as well as Aphrodite Basal Quartz tight natural gas, relieving pressure on the Hooker facilities. Compton has commenced engineering work on the 24-kilometre tie-in to Aphrodite and plans to drill four exploration wells in 2003.

OTHER AREAS

Compton drilled two exploration wells at Tsuu T'ina in 2002, both of which were cased and were undergoing testing in the first quarter of 2003. Compton plans further seismic acquisitions, workover of suspended wells and a possible new exploratory well during 2003.

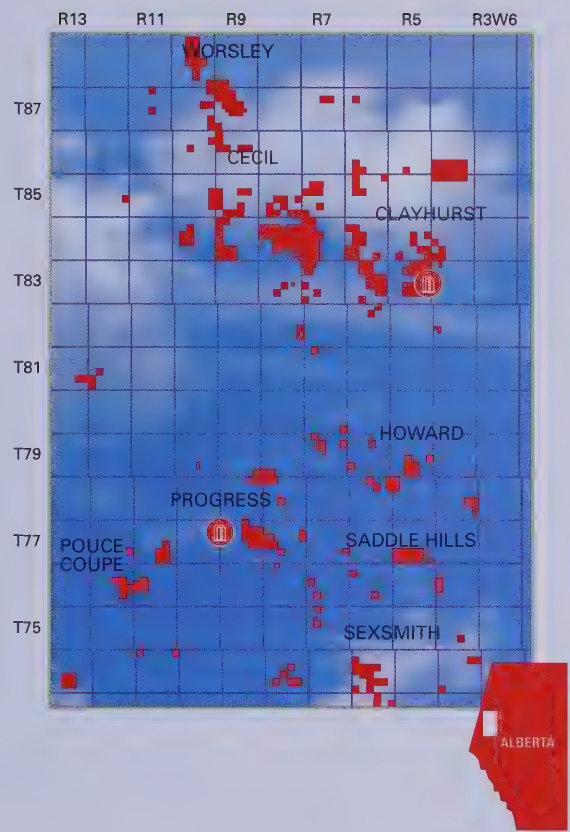
PEACE RIVER ARCH AND NORTHERN ALBERTA



The Peace River Arch area, located north of Grand Prairie, offers multi-zone potential for both exploration and development opportunities. The Company holds more than 211 sections of undeveloped lands in this area with an average 65 percent working interest. This core area offers both light oil production at Cecil/Worsley and natural gas exploration at Clayhurst, Howard and Pouce Coupe. Compton plans to apply the same strategy used in Southern Alberta to the Peace River Arch area. Industry activity in the Arch has been primarily directed to zones less than 1,500 metres deep, whereas Compton will use its drilling experience to test deeper zones in some of its exploration wells.

In 2002, exploitation activity focused on oil production from the Charlie Lake formation. At Worsley, Compton drilled eight wells to develop and extend the Charlie Lake L and M pool to the north. The wells commence production at rates exceeding 100 boe per day and stabilize at 50 boe per day in three to six months. A pilot waterflood of the Worsley pool commenced in June 2002 to optimize oil recovery. At year-end, response to the waterflood was evident in offsetting wells. The Cecil O pool waterflood was initiated in December 2002. Together, these two pools hold 187 million barrels of oil-in-place; however, the primary recovery factor is only five to seven percent. Pool-wide waterfloods have the potential to more than double oil recovery from the Charlie Lake reservoirs.

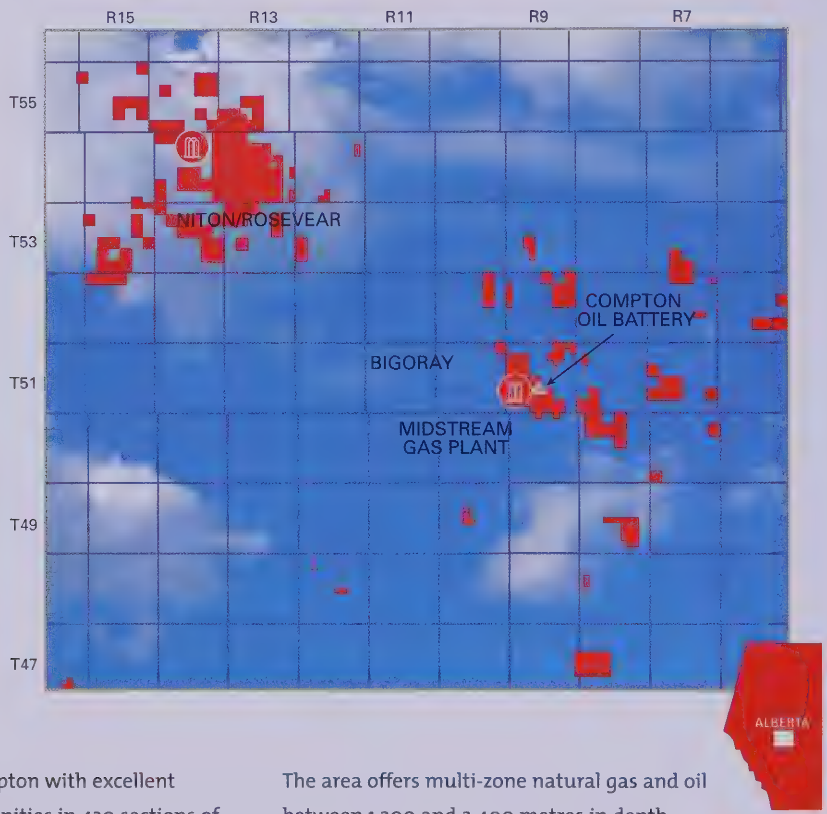
At Pouce Coupe, four non-operated natural gas wells commenced production from the Triassic Montney formation, a deep, tight sandstone that is similar to Hooker in depth and sand quality. These wells added net production of 3.5 mmcf of natural gas per day. Additional trend acreage at Pouce Coupe was acquired by Compton in 2002 and Compton drilled a successful Montney exploration well late in the year. A follow-up well is scheduled for the second quarter of 2003.



In the Peace River Arch, the Company drilled 16 wells in 2002, all of which were successful. In 2003, over 30 wells are planned in the area. Compton also plans to continue its aggressive seismic and land acquisition program in the Peace River Arch.

Northern Alberta is an area of multi-zone natural gas exploration for the Company. Compton holds more than 168 sections of undeveloped land in the West Rainbow area, near the British Columbia border. There is opportunity in several horizons, including sweet natural gas in the Bluesky and Mississippian, and sour gas in several Devonian carbonates. The area has strong potential, but will not be a focus area for Compton in 2003.

CENTRAL ALBERTA



Central Alberta provides Compton with excellent development drilling opportunities in 430 sections of undeveloped land and is an important balance to the Company's exploration programs in other core areas. Bigoray provides cash flow generated by mature, light oil production from six light oil pools: the Nisku D, E and F pools; the Cardium B pool; the Pekisko F pool and from the Ostracod natural gas discovery. In 2002, activity in Bigoray concentrated on exploitation opportunities from producing properties. The Bigoray Cardium B pool waterflood maintained production at 1,000-1,200 barrels of oil per day.

In 2002, Compton completed a land transaction at Niton/Rosevear that increased the Company's undeveloped land base by 100 sections, provided a 100 percent working interest in a 10 mmcf per day natural gas plant, and added production of 220 boe per day.

The area offers multi-zone natural gas and oil between 1,200 and 2,400 metres in depth.
Since acquiring the property, Compton has successfully pursued several exploitation opportunities and plans to drill 11 wells in 2003. Similar to Hooker, Rosevear is also located in a center-basin gas system. Compton plans to use its Hooker expertise to exploit similar zones.

Compton also continued its exploitation activity in the Halkirk/Gilby area in 2002. At Halkirk, two successful Glauconite oil wells increased pool production and extended the boundaries of the waterflooded A and F pools. The Company plans to drill up to four new wells at Halkirk in 2003 and to continue optimizing the waterflood. A number of wells are candidates for workovers, which will add production at a low cost. Additionally, Compton assumed operatorship with a 71 percent working interest in the 5 mmcf per day Halkirk gas plant.

ENVIRONMENT, HEALTH AND SAFETY

ENVIRONMENT

Compton recognizes the importance of protecting the environment and is committed to conducting all operations in a safe manner that minimizes environmental impact. This commitment is demonstrated with the following initiatives and endeavours:

- The Company conducts annual environmental audits to ensure that its facilities continually meet or exceed regulatory standards.
- Compton evaluates the environmental impact of all new projects, ensures that effective controls are implemented and acts in a timely and efficient manner to rectify deficiencies that may occur.
- Compton supports individual and industry efforts to protect the environment and pursues a high standard in environmental management.
- Compton has operations-focused employees attend appropriate environmental orientation sessions to become familiar with the sensitivity of the environment in which they work and to ensure they understand their responsibilities for environmental protection.
- Contractors working for Compton must also be dedicated to protecting the environment and must comply with the Company's policies and procedures, and all applicable laws and regulations.

HEALTH AND SAFETY

Compton continually strives to achieve a healthier and safer environment throughout its operations and at all work sites. The Company is committed to ensuring that all employees, contractors, and subcontractors are made aware of and adhere to all safety practices governed by regulatory legislation, industry guidelines and the Company. The Company has pledged to operate in a safe manner to protect the safety and health of employees, contractors and community residents.

The Company will continue to work with employees, contractors, subcontractors and community residents in maintaining a safer environment for all stakeholders.

Compton has established an Engineering, Environmental, Health and Safety Committee, consisting of four independent directors of Compton's Board, to ensure that the highest level of operations are maintained so that employees, community residents and the environment are protected while the Company is engaged in its exploration and development activities.

CORPORATE GOVERNANCE

MEL F. BELICH, Q.C., CHAIRMAN

Compton's approach to corporate governance aligns closely with the guidelines of the Toronto Stock Exchange ("TSX") for effective corporate governance. The Company addresses the TSX guidelines through Board composition, stated responsibilities of the Board and through various committees of the Board, as outlined below.

COMPOSITION OF THE BOARD

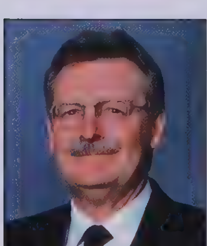
IRVINE J. KOOP, P. ENG

Compton is in full compliance with the TSX recommendation that the board of every corporation should have a majority of individuals who qualify as unrelated directors. An "unrelated director" is one who is "independent of management and is free from any interest or business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding". Compton's Board of Directors is comprised of five directors, four of whom, including the Chairman of the Board, qualify as unrelated directors. The President and the Chief Executive Officer is the only member of the Company's management who is a director.

JOHN W. PRESTON

RESPONSIBILITIES OF THE BOARD

The Board of Directors has explicitly assumed responsibility for the stewardship of the Company. As part of that responsibility, the Board ensures that (i) the Company has established long-term goals and a strategic planning process; (ii) the principal risks of the Company's business are identified and appropriate systems are implemented to manage those risks; (iii) there is sufficient succession planning including managing and monitoring management; (iv) the Company has a communications policy; and (v) the Company's internal controls and management information systems have sufficient integrity. The Board of Directors has the responsibility to oversee the conduct of the business of Compton and to oversee the activities of management who are responsible for the day-to-day conduct of the business. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to provide stewardship in order that the Company meets its obligations on an ongoing basis and that the Company operates in a reliable and safe manner.



JEFFREY T. SMITH, P. GEOL.

COMMITTEES OF THE BOARD

There are three committees of the Board: the Governance and Compensation Committee; the Audit, Finance and Risk Committee; and the Engineering, Environmental, Health and Safety Committee. All committees are composed exclusively of outside directors.

ERNEST G. SAPIEHA, C.A.

GOVERNANCE AND COMPENSATION COMMITTEE

The Governance and Compensation Committee's mandate is to (i) develop the Company's approach to governance issues; and (ii) review the Company's overall compensation policies and guidelines and corporate succession and development plans. The Committee is responsible for assessing the effectiveness of the Board as a whole as well as the various other committees and individual directors. It also monitors the relationship between management and the Board. The Committee is responsible for recommending candidates to the Board for nomination as directors and for the composition of various Board committees. The Committee also reviews and recommends compensation for Board and Committee service. The Committee is also mandated to undertake those initiatives as are necessary to maintain a high standard of corporate governance practices.

The Committee reviews succession plans for key management positions within the Company and the performance and development of the Chief Executive Officer and other senior officers of the Company. The Committee makes recommendations to the Board with respect to salary and other remuneration to be awarded to senior executive officers of Compton. It also makes recommendations to the Board in respect of all other compensation matters, including long and short-term incentives such as bonus, stock option plans and other benefits and is responsible for developing these programs.

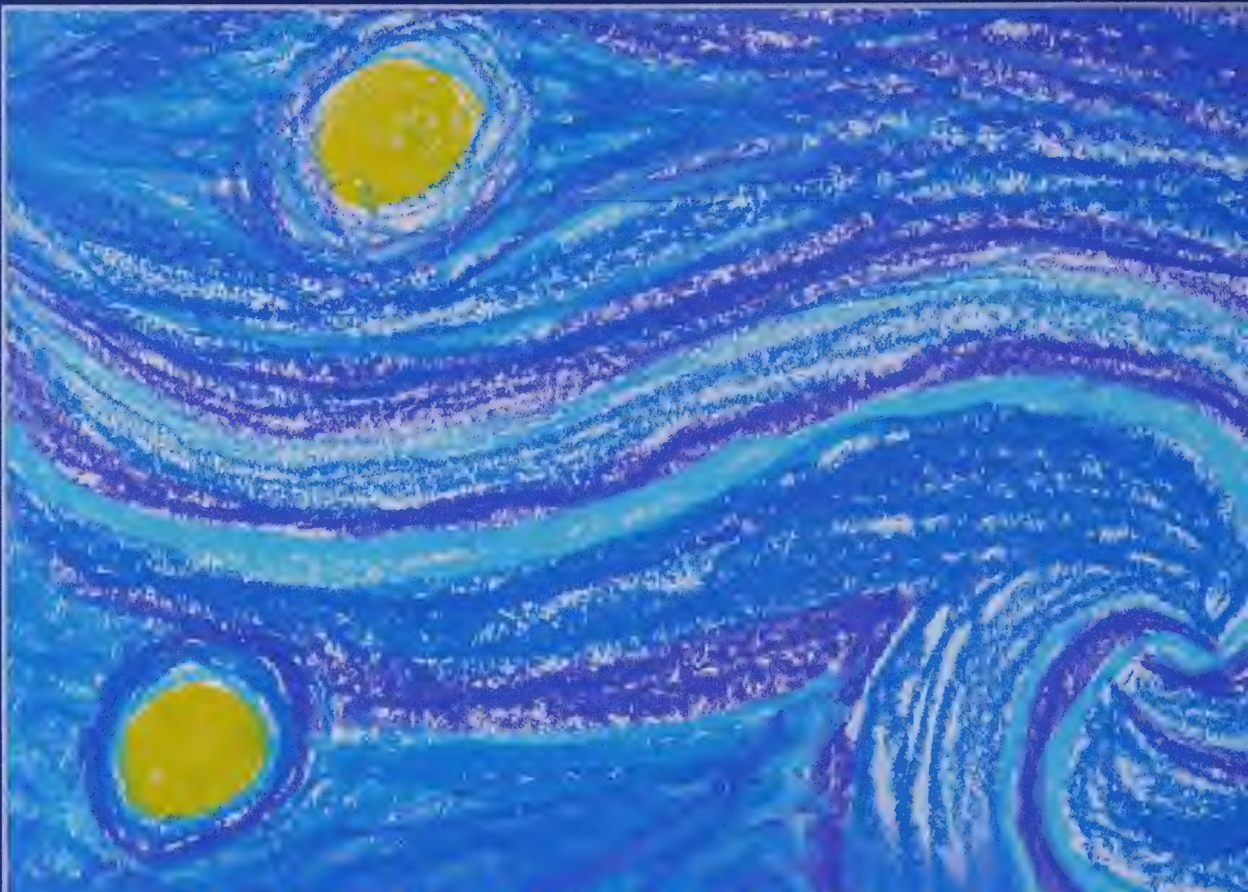
AUDIT, FINANCE AND RISK COMMITTEE

The Audit, Finance and Risk Committee's mandate is to assist the Board in the review, approval and issuance of the Company's financial statements, as well as considering and making recommendations to the Board in respect of matters related to risk management, technology, legislation and external business. The Committee has the responsibility to deal with the Company's external auditors and to implement and review the effectiveness and integrity of the financial information and reporting systems.

The Committee is also responsible for implementing practices intended to preserve the independence of the external auditors, including reviewing the recommendations of management in respect of appointment of the external auditors, reviewing the terms of the external auditors' engagement, reviewing engagements to be provided by the auditors and reviewing all reportable events.

ENGINEERING, ENVIRONMENTAL, HEALTH AND SAFETY COMMITTEE

The Engineering, Environmental, Health and Safety Committee's mandate is (i) to consider and make recommendations to the Board and review on an ongoing basis the Company's overall policies and guidelines with respect to engineering and reserves; and (ii) to monitor the environmental, health and safety practices and procedures of Compton for compliance with applicable legislation, conformity with industry standards and prevention or mitigation of losses. The Committee reviews reports and when appropriate makes recommendations to the Board on the Company's policies and procedures related to environment, health and safety. The Committee is also responsible for the review of the oil and natural gas procedures and practices of the Company's independent evaluator. In addition, the Committee considers, reviews and reports to the Board on the scope of the annual review of the reserves by the independent consultants and the evaluation of the Company's oil and natural gas reserves.



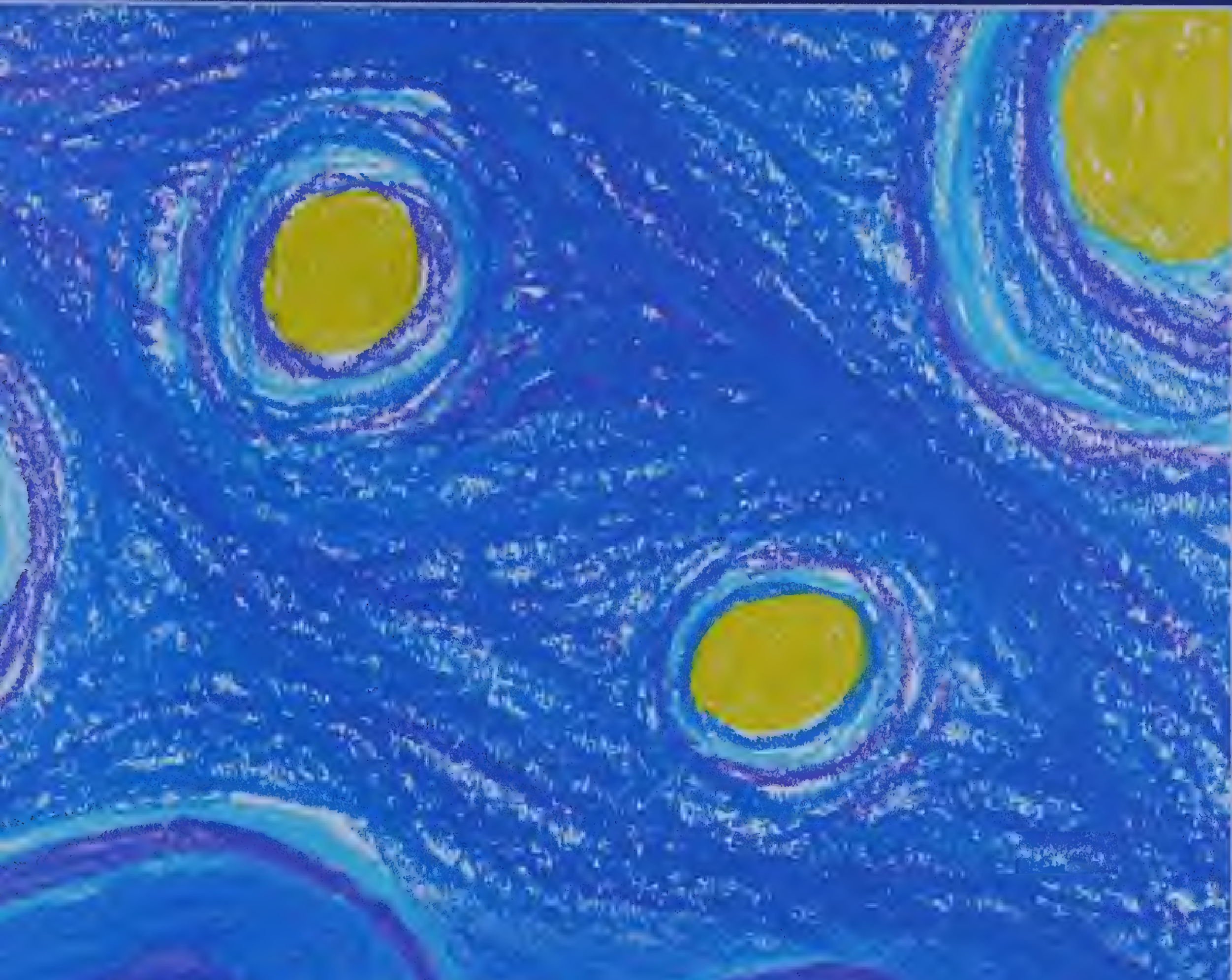
CORPORATE CITIZENSHIP

Compton employees recognize the importance and positive impacts that result from responsible corporate citizenship. Our Corporate Sponsorship and Donation Programs contribute to community-based projects and programs that enhance the quality of life in the communities where we work and live.

OUR EDUCATIONAL PARTNERSHIPS

For the past two years, Compton has participated in a Corporate/Educational Partnership with a Calgary Board of Education public school. During the 2001-2002 school year, Compton's educational partner was Cecil Swanson Elementary School. Working closely with the school, students participated in activities such as listening to the Calgary Philharmonic Orchestra and an "Artist in Residence" program. Compton employees also helped to construct a new creative playground at Cecil Swanson.

During the 2002-2003 school year, Compton is participating in an educational partnership with Alex Munro Elementary School. Compton will purchase a commemorative book, "M is for Maple" by Mike Ulmer, for each student. Students will also attend a Canadian film at the Imax and attend a French Canadian performance by Les Bucheron.



OUR COMMUNITY PARTNERSHIPS

Compton and its employees actively support projects and activities in the communities were we live and work. This spring and summer, Compton will employ several university students, who will work at Alex Munro Elementary School or the Calgary YMCA. This is a unique joint venture providing employment for university students while benefiting Alex Munro and the YMCA.

Compton recognizes the importance of protecting the environment and is committed to environmentally responsible practices and charitable causes. Compton joined Ducks Unlimited Canada as a corporate sponsor in 2002. Ducks Unlimited conserves, restores and manages wetlands and associated habitats for North America's waterfowl. This pledge will be given over a two-year period to the Calgary, High River, Drayton Valley and Fairview Banquet Committees.

Additionally, Compton and its employees annually support the United Way. Corporate donations were also made to Gladys 4-H Beef Club, Nanton Community Memorial Centre, Strathmore Community Crisis Centre, the Pacific Salmon Foundation, the Canadian Cancer Society, Alzheimers Society of Alberta, Canadian Cerebral Palsy Sports, Tsuu T'ina basketball and rodeo, the Alberta Sport Recreation Park, the Olympic Association and Theatre Calgary.

Pastel drawing [illegible]

COMPTON'S TEAM

"COMPTON'S TEAM IS COMPRISED OF OUTSTANDING INDIVIDUALS WITH A STRONG PASSION FOR LIFE AND THEIR WORK. THEIR HEARTS AND MINDS ARE FULL OF IDEAS, DREAMS AND CONVICTIONS.

COMPTON'S SUCCESS WOULD NOT BE POSSIBLE WITHOUT THEM. ON BEHALF OF SHAREHOLDERS AND THE BOARD OF DIRECTORS, I WISH TO THANK YOU FOR YOUR OUTSTANDING CONTRIBUTION."

E.G. SAPIEHA

MANAGEMENT'S DISCUSSION AND ANALYSIS

OVERVIEW

Management's discussion and analysis is a review of the Company's 2002 financial and operating results and should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2002. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to United States GAAP is included in Note 17 to the consolidated financial statements.

Per boe amounts have been calculated using a conversion rate of 6,000 cubic feet of natural gas being equivalent to one barrel of crude oil. Management's discussion and analysis may contain certain forward-looking statements under the meaning of applicable securities laws. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. Although Compton Petroleum Corporation ("Compton" or the "Company") believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward-looking statements not to be correct, including risks and uncertainties inherent in the Company business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards and mechanical failures, uncertainties in the estimates of reserves and in projections of future rates of production and timing of development expenditures, general economic conditions, and the actions or inactions of third-party operators. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement.

Management's Discussion and Analysis contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Company's financial performance. Compton's determination of cash flow from operations may not be comparable to that reported by other companies. The other items required to arrive at cash flow from operating activities are considered to be corporate charges.

Compton is an independent public company actively engaged in the exploration, development, and production of natural gas, natural gas liquids, and crude oil in Western Canada. The Company's activities are concentrated in three core geographic areas in Alberta. Compton's growth and reserves base have resulted from exploration and development activities complemented by strategic acquisitions. The Company is committed to long-term sustainable growth through a focus on natural gas with deeper, long-life, low-decline reserves.

RESULTS OF OPERATIONS

UNDEVELOPED LAND

During 2002, Compton continued to expand its land base within its core operating areas. Undeveloped land increased by 6 percent to 742,465 net (1,042,923 gross) acres, from 700,695 net (962,259 gross) acres in 2001. The Company has an average 71 percent working interest in this large land base, sufficient to generate a minimum of five years of drilling prospects.

Compton's landholdings are as follows:

	Acres		Sections	
Area	Gross	Net	Gross	Net
Southern Alberta	473,501	372,871	740	583
Central Alberta	275,108	168,107	430	263
Peace River Arch	135,200	96,018	211	150
Northern Alberta	107,210	82,165	168	128
Other	51,904	23,304	81	36
December 31, 2002 total	1,042,923	742,465	1,630	1,160
December 31, 2001 total	962,259	700,695	1,504	1,095
December 31, 2000 total	763,503	610,640	1,193	954

ACQUISITIONS

During the fourth quarter of 2002, the Company completed two strategic land and facility acquisitions. At Callum, immediately south and west of Hooker in Southern Alberta, the Company acquired a 50 percent working interest and operatorship of a 30 mmcf per day natural gas plant, 95 sections of contiguous undeveloped lands and 1.9 million boe of established, deep tight natural gas reserves. The undeveloped acreage is prospective for deep, tight natural gas targets and is an expansion of Compton's core area in Southern Alberta.

At Niton, in West-Central Alberta, Compton expanded its land position by swapping 100 sections of high working-interest lands, wells and facilities for non-operated minor working interests in the southern Peace River Arch. The Niton lands contain primarily multi-zone natural gas reserves and includes a 100 percent interest in a 10 mmcf per day gas plant.

CAPITAL EXPENDITURES

The Company continued to invest in land, seismic, production facilities and exploratory drilling necessary for future value creation. In 2002, drilling and completions accounted for 48 percent of capital expenditures of $155 million. The remaining 52 percent of capital expenditures were split amongst land, facilities and property acquisitions, similar to 2001.

Capital Expenditures	**2002** ($000s)	**2002** %	2001 ($000s)	2001 %	2000 ($000s)	2000 %
Drilling and completions	**75,369**	**48**	84,658	44	66,695	56
Land and seismic	**29,096**	**19**	25,883	14	23,241	20
Facilities	**21,714**	**14**	27,643	15	27,901	24
Acquisitions, net	**28,929**	**19**	22,614	11	635	–
Subtotal	**155,108**	**100**	160,798	84	118,472	100
Corporate acquisitions	**–**	**–**	29,669	16	–	–
Total	**155,108**	**100**	190,467	100	118,472	100

DRILLING ACTIVITY

In 2002, consistent with the Company's strategy of internal prospect generation and full-cycle exploration, Compton drilled a total of 87 gross wells, compared to 95 gross wells in 2001. In 2001, 48 percent of wells drilled were exploratory and 52 percent were development. In 2002, of the 87 wells drilled, 35 percent were classified as exploratory wells and 65 percent were classified as development wells.

Compton's 2002 drilling program achieved an overall success rate of 90 percent. Drilling results are summarized below:

Area	Natural gas	Oil	D&A	Total	Net	Success
Southern Alberta	51	0	7	58	46	88%
Central Alberta	3	2	1	6	4	83%
Peace River Arch	10	12	1	23	14	96%
2002 total	64	14	9	87	64	90%
2001 total	60	12	23	95	71	76%
2000 total	56	10	30	96	78	70%

Compton's natural gas targets continue to be deeper than the typical Alberta well. The average well depth of the Company's 2002 drilling program was approximately 1,789 metres (5,869 feet). Compton's deep drilling technical expertise and its large land base enable the Company to explore for and develop larger reservoirs with long-life, low-decline reserves.

RESERVES

Compton's proven reserves increased by 15 percent to 82.2 million boe at December 31, 2002 from 71.8 million boe at December 31, 2001. Total proven reserves comprised 79 percent of the Company's established reserves at December 31, 2002 compared to 86 percent at year-end 2001. As a result of successful development activities, proven undeveloped reserves were moved to the proven producing and non-producing categories and decreased by approximately 2.2 million boe. Proven undeveloped reserves comprised only 7 percent of total proven reserves at December 31, 2002 compared to 11 percent of proven reserves at December 31, 2001. Risked probable reserves increased by 79 percent to 21.3 million boe at December 31, 2002, further illustrating the extensive development opportunities existing within the Company.

In 2002, Compton focused on the continued development of its internally-generated prospects, with 76 percent of 2002 reserves additions generated through drilling activities. Overall, natural gas comprised 82 percent of the Company's proven reserves (80 percent of established). On a 10 percent discounted cash flow basis, the established value of reserves increased by 35 percent to $908.3 million at December 31, 2002 from $672.3 million at December 31, 2001.

The Company's reserves were evaluated by independent petroleum engineering consultants, Outtrim Szabo and Associates Ltd. and were reviewed by an independent committee of Compton's Board of Directors. A summary of the report is presented below:

Reserves at December 31, 2002 Escalating Economics	Natural gas (bcf)	Crude oil and ngls (mbbls)	Total oil equivalent (mboe) (6:1)	% of total	Discounted cash flow 10% DCF ($000s)	15% DCF ($000s)
Proven						
Producing	289	10,934	59,102	57	531,947	437,405
Non-producing	86	2,862	17,259	17	173,467	145,844
Undeveloped	27	1,356	5,795	6	61,737	48,860
Total proven	402	15,152	82,156	80	767,151	632,109
Risked probable	95	5,441	21,345	20	141,139	104,127
Established	497	20,593	103,501	100	908,290	736,236

The value of oil and natural gas reserves is based upon commodity price assumptions at January 1, 2003 and reflects a per barrel oil price (Edmonton Light) of $39.73 (WTI: US$26.00) for 2003, decreasing to $32.88 (WTI: US$21.00) in 2005, and then escalating to $37.59 (WTI: US$24.74) in 2014 and 1.5 percent per year thereafter. Natural gas pricing is based upon an Alberta spot price of $5.66 per mcf in 2003, declining to $4.63 in 2005 and then escalating to $5.13 in 2014 and 1.5 percent per year thereafter.

Reserve Reconciliation

	Crude oil and ngls			Natural gas		
	Proven (mbbls)	50% Probable (mbbls)	Total (mbbls)	Proven (bcf)	50% Probable (bcf)	Total (bcf)
December 31, 2001	13,083	3,751	16,834	352	49	401
Development, exploration and exploitation	3,656	1,136	4,792	72	31	103
Acquisitions, net	660	405	1,065	11	4	15
Reserve revisions	126	149	275	7	11	18
Production	(2,373)	0	(2,373)	(40)	0	(40)
December 31, 2002	15,152	5,441	20,593	402	95	497

EFFICIENCY MEASURES

Compton's 2002 finding and development ("F&D") costs are among the best in the industry. Reserve additions for 2002 were achieved at an all-in F&D cost of $7.92 per boe on a proven basis and $5.35 per boe established. On a five-year average basis, which is more reflective of full-cycle exploration, F&D costs are $7.59 per boe proven and $6.30 per boe established.

The recycle ratio is used as an indicator of the efficiency with which an exploration and production company can replace its produced reserves. As such, the recycle ratio is widely accepted as a measure of value creation. In 2002, Compton generated an established recycle ratio of 1.9 times.

				Average	
	2002	2001	2000	3 Year	5 Year
Proven reserve additions					
F&D costs ($/boe)	**7.92**	9.88	8.67	8.84	7.59
Recycle ratio	**1.3**	1.5	1.8	1.5	1.6
Reserve replacement ratio	**2.0**	2.3	1.8	2.1	2.6
Established reserve additions					
F&D costs ($/boe)	**5.35**	9.90	7.11	7.15	6.30
Recycle ratio	**1.9**	1.5	2.2	1.9	2.0
Reserve replacement ratio	**3.2**	2.3	2.2	2.6	3.2

Reserve Life Index

(Years)	Natural gas	Crude oil and ngls	2002 oil equivalent	2001 oil equivalent	2000 oil equivalent
Proven	9.9	6.4	8.9	7.8	7.5
Established	12.2	8.7	11.2	9.1	9.0

Compton's 2002 reserve life index is 8.9 years proven and 11.2 years established, further illustrating the long life of the Company's reserves.

NET ASSET VALUE

The Company's net asset value as at December 31, 2002 was $6.48 per common share, based upon established reserves (escalated dollar pricing) discounted at 10 percent. The Company's 2002 established reserves increased by 24 percent, contributing to an increase of 33 percent in net asset value from December 31, 2001.

($millions, except per share amounts)	**2002**	2001	2000
Oil and natural gas reserves, established, 10% DCF	**908.3**	672.3	678.8
Undeveloped land and seismic	**110.0**	100.7	98.4
Other	**3.6**	2.8	1.6
	1,021.9	775.8	778.8
Corporate debt, net	**(268.5)**	(208.3)	(153.4)
Net asset value	**753.4**	567.5	625.4
Net asset value per share, issued and outstanding	**6.48**	5.02	5.75

PRODUCTION

Compton's production profile continues to reflect the Company's focus on natural gas which accounted for approximately 74 percent of 2002 production. Compton's natural gas production averaged 112 mmcf per day in 2002, an increase of 11 percent from 2001. Liquids production decreased by 1 percent to 6,503 barrels per day from 6,546 barrels per day in 2001. On a boe basis, production for 2002 averaged 25,137 boe per day, a 7 percent increase from 23,404 boe per day in 2001.

Production for 2003 is expected to increase by approximately 11 percent over 2002, based upon the Company's 2003 capital expenditures program of $171 million.

The Company's success in Southern Alberta has resulted in processing and gathering facilities currently operating at maximum capacity. Operational constraints were experienced at the Mazeppa gas plant in the fourth quarter of 2002 as the plant had not previously operated at maximum capacity and due to the high liquids content of natural gas from Hooker. These problems have generally been resolved.

Compton is actively pursuing expansion of the Mazeppa plant by adding an additional 30 mmcf per day capacity by the third quarter of 2003. Additional plans are underway to offload Brant production to an alternative sales pipeline by the end of the second quarter in 2003, adding 15 mmcf per day capacity.

To further address temporary processing constraints, Compton acquired a 50 percent interest in a 30 mmcf per day natural gas processing plant (28 mmcf per day current unutilized capacity) in the fourth quarter of 2002. Also included in the purchase were 1.9 million boe of established reserves, 1 mmcfe per day of net production and a 50 percent interest in 95 contiguous sections of undeveloped lands in the Callum area of Southern Alberta. Compton intends to build a pipeline from Aphrodite to the Callum plant by the fourth quarter of 2003.

CONSOLIDATED FINANCIAL RESULTS

CASH FLOW AND NET EARNINGS

Cash flow from operations in 2002 was $96.5 million ($0.85 per share basic), a 25 percent decrease from 2001 cash flow from operations of $128.3 million ($1.17 per share basic). Net earnings for the year totalled $18.8 million ($0.17 per share basic), a 66 percent decrease from the $55.6 million ($0.51 per share basic) earned in 2001. The Company's 2002 cash flow and net earnings benefited from increased production volumes; however, the results were affected by lower realized commodity prices. Net earnings included a net loss of $1.6 million related to an unrealized foreign exchange loss due to the translation of the Company's U.S. dollar seven-year notes.

Netbacks	2002			2001	2000
($/boe @ 6:1)	**Natural gas**	**Crude oil and ngls**			
	($/mcf)	**($/bbl)**	**($/boe)**	($/boe)	($/boe)
Revenue	**3.67**	**29.43**	**23.95**	28.68	28.54
Royalties, net	**(0.86)**	**(5.18)**	**(5.17)**	(6.55)	(5.98)
Operating expenses	**(0.83)**	**(4.96)**	**(4.96)**	(4.71)	(4.22)
Field operating netback	**1.98**	**19.29**	**13.82**	17.42	18.34
General and administrative			**(1.07)**	(0.74)	(0.79)
Interest expense			**(2.19)**	(1.51)	(1.71)
Capital taxes			**(0.17)**	(0.16)	(0.12)
Cash flow netback			**10.39**	15.01	15.72

QUARTERLY INFORMATION

The following table sets forth certain quarterly financial information of the Company for the last two fiscal years:

($000s, except per share data)	**Fiscal 2002 Three Months Ended**			
	March 31, 2002	**June 30, 2002**	**Sept. 30, 2002**	**Dec. 31, 2002**
Total revenue	**42,548**	**54,018**	**50,889**	**72,332**
Earnings before tax	**6,406**	**18,325**	**(6,434)**	**20,696**
Earnings	**3,472**	**11,026**	**1,447**	**2,853**
Earnings per share (basic)	**0.03**	**0.10**	**0.01**	**0.03**
Earnings per share (diluted)	**0.03**	**0.09**	**0.01**	**0.02**
Total assets	**700,553**	**717,496**	**751,773**	**817,272**
Total long-term debt	**230,000**	**250,586**	**261,740**	**260,634**

($000s, except per share data)	Fiscal 2001 Three Months Ended			
	March 31, 2001	June 30, 2001	Sept. 30, 2001	Dec. 31, 2001
Total revenue	87,197	66,415	47,927	43,431
Earnings before tax	40,793	26,743	11,004	5,621
Earnings	19,526	27,485	3,593	2,267
Earnings per share (basic)	0.20	0.26	0.07	0.02
Earnings per share (diluted)	0.19	0.24	0.07	0.02
Total assets	549,488	569,815	653,310	693,973
Total long-term debt	182,000	182,000	230,371	230,000

REVENUE AND PRICING

Compton realized $219.8 million in petroleum and natural gas revenue in 2002, a decrease of 10 percent from $245.0 million generated the previous year. The decrease in revenue resulted from lower natural gas prices realized in 2002 than in 2001, despite increased production in 2002. The Company's average 2002 realized oil and natural gas liquids price increased by 2 percent from 2001 to $29.43 per boe. In 2002, Compton's average realized natural gas price was $3.67 per mcf, down 23 percent from the 2001 average of $4.77 per mcf.

Revenue ($000s)	**2002**		2001		2000	
	$	**%**	$	%	$	%
Natural gas	**148,133**	**67**	174,424	71	141,367	67
Natural gas hedging	**1,789**	**1**	3,666	1	0	0
Crude oil and ngls	**70,297**	**32**	68,880	28	79,664	37
Crude oil hedging	**(432)**	**0**	0	0	(7,655)	(4)
Revenue	**219,787**	**100**	244,970	100	213,376	100

MARKETING

In 2002, the Company's realized average field prices in Canadian funds were $3.67 per mcf of natural gas and $29.43 per barrel of crude oil and natural gas liquids, compared to the 2001 average field prices of $4.77 per mcf and $28.83 per barrel.

Compton's natural gas production is sold under a combination of longer-term contracts with aggregators and short-term 30-day AECO-indexed contracts. Approximately 40 percent of the Company's natural gas production in the first three-quarters of 2002 was committed to aggregators, reducing to 18 percent in the last quarter as a number of aggregator contracts expired. The average aggregator price realized was approximately $0.94 per mcf less than the non-aggregator prices realized during the year. The fourth-quarter aggregator price was $1.12 per mcf lower than non–aggregator prices.

Compton's crude oil sales are priced at Edmonton postings and are typically sold on 30-day evergreen arrangements. Natural gas liquids are bid out on an annual basis to establish the most competitive pricing. The Company sells crude oil and natural gas liquids primarily to refineries and marketers of crude oil and natural gas liquids.

From time to time, Compton may enter into hedging arrangements to mitigate commodity price risk. In accordance with Compton's policy, hedging programs will not exceed 50 percent of non-contracted production. See Risk Mitigation discussion on page 39 for outstanding hedges.

ROYALTIES

($000s, except where noted)	2002	2001	2000
Crown royalties	**38,902**	44,075	39,159
Other royalties	**9,095**	12,344	6,188
	47,997	56,419	45,347
Alberta Royalty Tax Credit	**(500)**	(500)	(652)
Net royalties	**47,497**	55,919	44,695
Percentage of revenue	**21.6%**	22.8%	20.9%

The Company's royalty obligations for 2002, net of the Alberta Royalty Tax Credit, amounted to $47.5 million, a decrease of 15 percent from the previous year. This decrease is attributable to lower revenues in 2002 and the effects of the provincial sliding-scale Crown royalty structure, which imposes lower royalty rates at lower commodity prices. The average royalty rate on total production was 21.6 percent in 2002, compared to 22.8 percent in the preceding year.

OPERATING EXPENSES

	2002	2001	2000
Operating expenses ($000s)	**45,546**	40,222	31,571
Operating expenses per boe ($/boe)	**4.96**	4.71	4.22

Operating expenses totalled $45.5 million in 2002. On a unit-of-production basis, operating costs were $4.96 per boe compared to $4.71 per boe during the same period in 2001, an increase of 5 percent year-over-year. The general increase in the cost of goods and services in the oil and natural gas industry, together with increased field staff levels and higher energy costs, contributed to the Company's higher operating costs on a unit-of-production basis.

GENERAL AND ADMINISTRATIVE EXPENSES

($000s, except where noted)	2002	2001	2000
Gross G&A expense	**13,456**	9,805	8,094
Operating recoveries	**(3,611)**	(3,503)	(2,179)
Net G&A expense	**9,845**	6,302	5,915
Net G&A expense per boe ($/boe)	**1.07**	0.74	0.79

In 2002, the Company's general and administrative ("G&A") expenses totalled $9.8 million, compared to $7.8 million for the preceding year before a recovery of $1.5 million relating to stock-based compensation. On a boe basis, G&A costs were $1.07, an increase of 18 percent from the $0.91 incurred in 2001. Additional full-time employees required due to the expanded activities of the Company and increased insurance expense contributed to increased G&A in 2002.

In 2001, the Company adopted the new recommendations of the Canadian Institute of Chartered Accountants ("CICA") with respect to stock-based compensation. As a result, the Company recorded a recovery of $1.5 million of non-management employee stock-based compensation costs in 2001 resulting in net G&A expense of $6.3 million for 2001.

INTEREST EXPENSE

($000s)	**2002**	2001	2000
Interest expense	**20,130**	12,863	12,772
Average debt outstanding	**265,605**	203,410	153,815

The Company's interest expense in 2002 totalled $20.1 million compared to $12.9 million for the previous year. The increased interest expense is attributable to higher debt servicing costs associated with the long-term U.S. notes issue and includes $1.7 million of non-cash charges.

DEPLETION, DEPRECIATION AND SITE RESTORATION COSTS

The Company's depletion and depreciation expense, which includes a provision for the future costs of site restoration and abandonment, increased to $56.0 million from $50.5 million in 2001. The average cost in 2002 was $6.10 per boe, slightly higher than $5.91 per boe in 2001.

On an annual basis, Compton reviews its liability for future site restoration and abandonment costs. For 2002, the provision totalled $1.1 million compared to $0.7 million in 2001. Current costs for site restoration and abandonments net of recoveries, were estimated at approximately $18.8 million, of which $2.2 million is reflected as an accumulated provision in the December 31, 2002 consolidated balance sheet.

TAXES

Capital Tax

Compton is liable for the payment of federal Large Corporations Tax ("LCT"). In 2002, the LCT increased to $1.4 million from $1.3 million in 2001, due to an increase in the Company's capital base upon which the LCT is calculated. This tax is non-deductible and increases as the capital resources of the Company increase.

Future Income Tax Expense

The Company's future income taxes were $18.8 million in 2002 compared to $22.2 million in 2001. The 2002 expense is lower due to a combination of decreased earnings and lower resource allowance in 2002.

Tax Pools

Compton has approximately $274.4 million of tax pools at January 1, 2003. The following table summarizes the Company's estimated tax pool balances by classification:

	Available balance ($000s)	Maximum annual deduction
Canadian exploration expense	352	100%
Canadian development expense	48,996	30%
Canadian oil and gas property expense	145,812	10%
Undepreciated capital cost	79,265	20%-30%
Total	274,425	

LIQUIDITY AND CAPITAL RESOURCES

The capitalization of the Company at December 31, 2002 consisted primarily of $245.8 million of shareholders' equity and US$165 million senior term notes. Total debt outstanding at year-end, net of working capital, was $268.6 million. Working capital at December 31, 2002 was $32.1 million compared to $22.2 million in 2001, an increase of $9.9 million principally due to a higher cash balance at December 31, 2002 compared to December 31, 2001.

Compton expects funds generated from operations, together with available funds under the Company's existing bank credit facilities, will be sufficient to finance current operations and planned capital expenditures for 2003.

Debt

In May 2002, the Company issued US$165 million of 9.90 percent senior notes due 2009. The senior notes are unsecured and were issued at a price per note of 98.273 percent. The net proceeds from the offering were approximately US$157.2 million, which the Company used to repay its entire existing bank indebtedness and for general corporate purposes.

At December 31, 2002 the Company had drawn $40 million of its syndicated credit facility; $128 million remains available. The senior notes offering, the subsequent repayment of the Company's outstanding bank indebtedness and available line of credit enhances Compton's financial flexibility and facilitates its continuing strategy for long-term sustainable growth.

Equity

In December 2002, Compton completed a private placement of 3,085,175 flow-through common shares for total gross proceeds of approximately $17.6 million. The funds were utilized to fund the expansion of Compton's exploration operations.

In March 2002, Compton obtained regulatory approval from the Toronto Stock Exchange to repurchase a maximum of 5.4 million of the Company's outstanding common shares for cancellation. The repurchase program was approved for a 12-month period, which commenced on March 8, 2002 and ended on March 7, 2003 and was subsequently renewed in 2003 for a further 12-month period. For the year ended December 31, 2002, the Company repurchased 796,200 common shares under this program at an average cost of $3.80 per share.

ACCOUNTING POLICIES

The application of Canadian GAAP involves certain assumptions, judgements and estimates that affect reported amounts of assets, liabilities, revenues and expenses. The basis for these estimates is historical experience and various other assumptions that management believes to be reasonable. These estimates are the basis for making judgements about the carrying value of assets and liabilities. Actual results could differ from these estimates under different assumptions or conditions. Thus, the application of these principles can produce varying results from company to company.

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days of the filing of the report (the "Evaluation Date"), and concluded that, as of the Evaluation Date, the Company's disclosure controls and procedures are effective to ensure that information required to disclose in its filings with the Securities and Exchange Commission under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and to ensure that information required to be disclosed in the reports that it files under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Excecutive Officer and Chief Financial Office, as appropriate to allow timely decisions regarding required disclosure.

Changes to Internal Controls and Procedures for Financial Reporting

There were no significant changes to Compton's internal controls or in other factors that could significantly affect these controls subsequent to the Evaluation Date and the filing date of the Annual Report.

Full Cost Accounting

Compton follows the full cost method of accounting for petroleum and natural gas operations. Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proven reserves, are depleted using the unit-of-production method based on estimated proven oil and natural gas reserves.

Ceiling Test

In applying the full cost method, Compton calculates a ceiling test whereby the carrying value of petroleum and natural gas properties and production equipment, net of recorded future income taxes and the accumulated provision for site restoration and abandonment costs, is compared annually to an estimate of future net cash flow from the production of proven reserves. Net cash flow is estimated using year-end prices, less estimated future general and administrative expenses, financing costs and income taxes. Should this comparison indicate an excess carrying value, the excess is charged against earnings as additional depletion and depreciation.

Oil and Natural Gas Reserves

All of Compton's oil and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing or production levels.

Proven oil and natural gas reserves are those reserves that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Probable additional reserves are those reserves not currently demonstrated to be proven under existing economic and operating conditions, but where analysis suggests the likelihood of their existence and future recovery. Established reserves are calculated as proven reserves plus 50 percent of risked probables. Disclosed reserve quantities are gross of royalty volumes.

Asset Impairment

The Company is required to provide for future removal and site restoration costs, net of expected recoveries. The Company must estimate these costs in accordance with existing laws, contracts or other policies and must estimate the expected recoveries, which is generally the salvage value or residual value of an asset. These estimated net costs are charged to earnings and the appropriate liability account over the expected service life of the asset. Site restoration costs incurred in the year reduce the amount of the liability. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

Changes in Accounting Policy

Stock-based Compensation

During the fourth quarter of 2001, the Company early adopted the new recommendation of the Canadian Institute of Chartered Accountants ("CICA") with respect to accounting for stock-based compensation. The Company adopted this accounting policy retroactively, without restating the consolidated financial statements of prior periods. Under the fair value method, the Company records a compensation expense in the financial statements for granted share options.

The Company has a stock-based compensation plan, which includes stock options and an employee stock savings plan. Consideration received from employees or directors on the exercise of stock options under the stock option plan is recorded as capital stock. Compensation costs have not been recognized for fixed stock options granted to employees and directors. The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense.

Foreign Currency Translation

Effective January 1, 2002 the Company adopted the CICA amended accounting standard with respect to accounting for foreign currency translation. As a result of adopting this amended standard, gains or losses on the translation of long-term debt denominated in U.S. dollars are no longer deferred and amortized over the term of the debt, but are recognized in earnings.

Future Income Taxes

Effective January 1, 2000 the Company adopted the new recommendations of the CICA with respect to accounting for future income taxes. Under the new recommendations the liability method of tax allocation is used, which is based upon the difference between financial and tax bases of assets and liabilities.

2003 OUTLOOK

Compton is projecting an 11 percent increase in 2003 production over 2002. Average annual production growth in 2003 will be limited due to temporary facility constraints. Compton expects to drill 142 net wells, incurring capital expenditures of $171 million. Of this amount, approximately $101 million will be directed towards drilling and completion activities, allocated 35 percent to exploration and 65 percent to development projects.

The Company's 2003 capital expenditure program reflects estimated 2003 realized average commodity prices of $5.45 per mcf of natural gas and $34.85 per barrel of crude oil. These prices are based upon US$4.35 per mcf (NYMEX) and US$24.85 per barrel (WTI). The Company has a large inventory of drilling prospects and can quickly increase its capital expenditure program if commodity prices remain strong. The Company will fund its 2003 capital program with cash flow from operations.

Cash flow will be dependent upon a number of variables, including forecast prices and production. The table below outlines critical assumptions:

2003 Estimates

Production			
Natural gas (mmcf/d)			130
Oil and ngls (bbls/d)			6,500
Oil equivalent (boe/d)			28,000
Capital expenditures ($000s)		$	171,000
Wells drilled (net)			142
Pricing			
Natural gas	(US$/mcf) NYMEX	$	4.35
	(Cdn$/mcf) corporate	$	5.45
Crude oil	(US$/bbl) WTI	$	24.85
	(Cdn$/bbl) corporate	$	34.85
Exchange rate	(Cdn$ = US$)		0.65

Sensitivities

The Company's 2003 estimated cash flow is sensitive to fluctuations in oil and natural gas prices as follows:

Cash Flow (Cdn$)	($000s)	($/share basic)
Change of US$0.10/mcf in the price of natural gas (NYMEX)	5,000	$0.04
Change of US$1.00/bbl in the price of crude oil (WTI)	2,500	$0.02

BUSINESS CONDITIONS, RISKS AND RISK MITIGATION

BUSINESS CONDITIONS AND RISKS

Compton's operations are subject to risks normally associated with the oil and natural gas industry. The most important of these are set out below, together with the strategies Compton employs to mitigate and minimize these risks.

Inherent industry risk that exploration and development programs may not result in economic reserve additions to replace production. Compton's strategies to minimize this inherent risk include focusing on selected areas in Western Canada, utilizing a team of highly qualified professionals with expertise and experience in these areas, expanding operations in core areas, continuously assessing strategic acquisitions to complement existing activities and striving for a balance between exploration and lower-risk development and exploitation prospects.

Financial risks including commodity prices and expenditure costs shifting due to changes in market conditions. Commodity prices are driven by supply, demand and market forces outside the Company's influence. Compton monitors and focuses its expenditures to reflect price and production changes. Compton continuously monitors market conditions and opportunities. From time to time the Company will employ financial instruments to manage exposure related to Canada/U.S. exchange rates and commodity prices.

The Company has commodity and fixed-price contracts outstanding as outlined in the Risk Mitigation section of this MD&A. The Company considers longer-term contracts with suppliers, where appropriate, to mitigate shifts in costs resulting from changes in industry and market conditions. Compton has no control over government intervention or taxation levels on the industry.

It is likely that in the future the Company will be required to raise additional capital via debt and/or equity financings in order to fully realize its strategic goals and business plans. Compton's ability to raise additional capital will depend upon a number of factors, such as general economic and market conditions that are beyond its control. If Compton is unable to obtain additional financing or to obtain it on favourable terms, the Company might be required to forego attractive business opportunities. Compton is committed to maintaining a strong balance sheet, combined with a flexible capital expenditure program, that can be adjusted to capitalize on or reflect acquisition opportunities or a tightening of liquidity sources.

Mechanical and operational risks associated with the drilling for, production and processing of natural gas and crude oil, including damage to the Company's equipment and the liability associated with an occurrence or malfunction. Compton manages operational risks by employing skilled professionals utilizing leading-edge technology and conducting regular maintenance and training programs. The Company has both an operational emergency response plan and an operational safety manual. In addition, a comprehensive insurance program is maintained to mitigate risks and protect against significant losses where possible.

Compton operates in accordance with all applicable environmental legislation. The Company strives to maintain or surpass compliance with such regulations and works with government agencies, landholders and other parties to minimize the environmental impact of its activities.

Compton is also subject to various government-imposed regulatory risks, some of which are beyond the Company's control. Compton has established an Engineering, Environmental, Health and Safety Committee to ensure that employees and the environment are protected while the Company is engaged in its exploration and development activities. Policies and procedures have been established to ensure environmental protection standards are maintained and standards of operating practice are designed to minimize risk to employees and the environment.

RISK MITIGATION

From time to time, the Company enters into hedge transactions to manage fluctuations in commodity prices and foreign currency. Hedging contracts are utilized to support the economics of both corporate and property acquisitions. Oil and natural gas revenues for 2002 included gains of $1.2 million (2001 – gain of $3.7 million) on such transactions.

Currently, the Company has hedged approximately 30 percent of its current 2003 production and no hedging contracts are in place for 2004.

Hedging transactions have been entered into as follows:

Commodity	Type	Term	Daily volume	Price	Index
Natural gas	Collars	November 2002 – March 2003	23.8 mmcf	$4.33/mcf – $7.18/mcf	AECO
Natural gas	Collars	April 2003 – October 2003	33.3 mmcf	$4.88/mcf – $7.93/mcf	AECO
Natural gas	Fixed	April 2003 – October 2003	4.8 mmcf	$6.85/mcf	AECO
Crude oil	Fixed	January 2003 – December 2003	1,500 bbls	US$27.00/bbl	WTI
Crude oil	Collar	January 2003 – December 2003	500 bbls	US$23.50/bbl – US$27.00/bbl	WTI

Foreign currency	Type	Term	Daily notional amount	Exchange rate	Index rate
US$	Fixed	January 2003 – December 2003	US$37,250	Cdn$1.583 / US$1	Bank of Canada Noon

MANAGEMENT'S REPORT

The accompanying consolidated financial statements of Compton Petroleum Corporation and all other financial and operating information contained in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared in accordance with accounting policies detailed in the notes to the consolidated financial statements and in accordance with generally accepted accounting principles in Canada.

The Company's systems of internal control have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial records are sufficiently well maintained to provide relevant, timely and reliable information to management.

External auditors, appointed by the shareholders, have independently examined the consolidated financial statements. They have performed such tests as they deemed necessary to enable them to express an opinion on these consolidated financial statements.

An Audit Committee of the Board of Directors has reviewed these consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

E.G. Sapieha, C.A.
President and
Chief Executive Officer

N.G. Knecht, C.A.
Vice President Finance and
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Compton Petroleum Corporation:

We have audited the consolidated balance sheets of Compton Petroleum Corporation as at December 31, 2002 and 2001 and the consolidated statements of earnings and retained earnings and cash flow for each of the years in the three year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada and the United States of America. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosure in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and cash flow for each of the years in the three-year period ended December 31, 2002 in accordance with accounting principles generally accepted in Canada.

Calgary, Alberta
March 14, 2003

Grant Thornton LLP
Chartered Accountants

Comments by Auditor for U.S. Readers on Canada-U.S. Reporting Differences

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the changes described in Note 3 to the consolidated financial statements. Our report to the shareholders dated March 14, 2003 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

Calgary, Alberta
Canada
March 14, 2003

Grant Thornton LLP
Chartered Accountants

CONSOLIDATED
BALANCE SHEETS

($000s)

December 31,	**2002**	2001
Assets		
Current		
Cash	**$ 14,725**	$ 5,052
Accounts receivable and other	**80,689**	82,001
	95,414	87,053
Deferred financing charges	**13,444**	–
Property and equipment (Note 5)	**708,414**	606,920
	$ 817,272	$ 693,973
Liabilities		
Current		
Bank debt (Note 6)	**$ 40,000**	$ 230,000
Accounts payable	**63,275**	64,903
	103,275	294,903
Senior term notes (Note 7)	**260,634**	–
Capital lease obligations (Note 8)	**126**	449
Future income taxes (Notes 3 and 13)	**205,193**	179,192
Future site restoration (Note 9)	**2,245**	1,569
	571,473	476,113
Shareholders' Equity		
Capital stock (Note 10)	**128,079**	116,572
Retained earnings	**117,720**	101,288
	245,799	217,860
	$ 817,272	$ 693,973

Commitments and contingencies (Note 16)

On behalf of the Board:

Director

Director

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS
OF EARNINGS AND RETAINED EARNINGS

($000s, except per share data)

Years ended December 31,	**2002**	2001	2000
Revenue			
Oil and gas revenues	**$ 219,787**	$ 244,970	$ 213,376
Royalties, net	**(47,497)**	(55,919)	(44,695)
	172,290	189,051	168,681
Expenses			
Operating	**45,546**	40,222	31,571
General and administrative	**9,845**	6,582	5,915
Interest	**20,130**	12,863	12,772
Depletion and depreciation	**56,003**	50,450	41,767
	131,524	110,117	92,025
Unrealized foreign exchange loss (Note 3)	**1,583**	–	–
Stock-based compensation (Note 11)	**190**	(280)	–
	133,297	109,837	92,025
Earnings before taxes	**38,993**	79,214	76,656
Taxes			
Future income taxes (Note 13)	**18,767**	22,248	35,707
Capital taxes	**1,428**	1,330	890
	20,195	23,578	36,597
Net earnings	**18,798**	55,636	40,059
Retained earnings, beginning of year	**101,288**	63,324	27,197
	120,086	118,960	67,256
Change in accounting policies (Note 3)	**–**	(3,585)	(380)
Premium on redemption of shares (Note 10)	**(2,366)**	(14,087)	(3,552)
Retained earnings, end of year	**$ 117,720**	$ 101,288	$ 63,324
Earnings per share			
Basic	**$ 0.17**	$ 0.51	$ 0.37
Diluted (Note 12)	**$ 0.16**	$ 0.48	$ 0.36

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS
OF CASH FLOW

($000s, except per share data)

Years ended December 31,	2002	2001	2000
Cash derived from (applied to)			
Operating			
Net earnings	**$ 18,798**	$ 55,636	$ 40,059
Items not affecting cash			
Depletion and depreciation	**56,003**	50,450	41,767
Future income taxes	**18,767**	22,248	35,707
Amortization of deferred charges	**1,367**	–	–
Unrealized foreign exchange loss	**1,583**	–	–
Cash flow from operations	**96,518**	128,334	117,533
Change in non-cash working capital (Note 15)	**(4,843)**	(7,266)	(13,346)
	91,675	121,068	104,187
Financing			
Increase (decrease) in bank loan	**(190,000)**	36,304	23,662
Capital lease obligations	**(323)**	(38)	–
Issue of senior notes	**259,050**	–	–
Deferred financing charges	**(14,810)**	–	–
Proceeds from share issues, net	**18,177**	41,558	11,844
Redemption of common shares	**(3,026)**	(17,774)	(5,564)
Change in non-cash working capital (Note 15)	**3,514**	–	–
	72,582	60,050	29,942
Cash available for investing activities	**164,257**	181,118	134,129
Investing			
Property and equipment additions	**(127,993)**	(147,993)	(118,153)
Corporate acquisitions (Note 4)	**–**	(29,669)	–
Property acquisitions	**(44,857)**	(18,974)	(33,513)
Property dispositions	**17,700**	8,731	33,272
Site restoration	**(446)**	(473)	(368)
Change in non-cash working capital (Note 15)	**1,012**	12,312	(307)
	(154,584)	(176,066)	(119,069)
Change in cash	**9,673**	5,052	15,060
Cash, beginning of year	**5,052**	–	(15,060)
Cash, end of year	**$ 14,725**	$ 5,052	$ –
Cash flow from operations per share			
Basic	**$ 0.85**	$ 1.17	$ 1.10
Diluted (Note 12)	**$ 0.82**	$ 1.12	$ 1.06

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in $000s, unless otherwise stated)

December 31, 2002

1. NATURE OF OPERATIONS

The Company is engaged primarily in the exploration for and production of petroleum and natural gas reserves in a single cost centre, being the Western Canada Sedimentary Basin.

2. SIGNIFICANT ACCOUNTING POLICIES

A) BASIS OF PRESENTATION

The consolidated financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles within the framework of the accounting policies summarized below.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries from the respective dates of acquisition. Inter-company transactions and balances are eliminated upon consolidation.

B) PETROLEUM AND NATURAL GAS PROPERTIES

i) Capitalized costs

The Company follows the full cost method of accounting for its petroleum and natural gas operations. Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, interest on debt directly related to certain acquisitions, and costs of drilling both productive and non-productive wells. Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

ii) Depletion and depreciation

Depletion of exploration and development costs and depreciation of production equipment is provided using the unit-of-production method based upon estimated proven petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion. For depletion and depreciation purposes, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of office equipment is provided for on a declining-balance basis at 20 percent per annum.

2. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

iii) Ceiling test

In applying the full cost method, the Company calculates a ceiling test whereby the carrying value of petroleum and natural gas properties and production equipment, net of recorded future income taxes and the accumulated provision for site restoration and abandonment costs, is compared annually to an estimate of future net cash flow from the production of proven reserves. Net cash flow is estimated using year end prices, less estimated future general and administrative expenses, financing costs and income taxes. Should this comparison indicate an excess carrying value, the excess is charged against earnings as additional depletion and depreciation.

iv) Future site restoration and abandonment costs

Estimated costs of future site restoration and abandonments, net of recoveries, are provided for over the life of proven reserves on a unit-of-production basis. An annual provision is recorded as additional depletion and depreciation. Costs are based on engineering estimates of the anticipated method and extent of site restoration in accordance with current legislation, industry practices and costs. The accumulated provision is reflected as a non-current liability and actual expenditures are charged against the accumulated provision when incurred.

C) FINANCIAL INSTRUMENTS

Financial instruments consist mainly of accounts receivable and other, accounts payable and long-term debt. There are no significant differences between the carrying value of these financial instruments and their estimated fair value.

The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates, as described in Note 14. Hedge accounting is used when there is a high degree of correlation between price movements in the financial instrument and the item designated as being hedged. Gains and losses are recognized in the same period as the hedged item. If correlation ceases, hedge accounting is terminated and future changes in the market value of the financial instrument are recognized as gains or losses in the period. To date, the correlation has remained strong and all gains and losses from these financial instruments have been recorded using hedge accounting.

D) JOINT OPERATIONS

Certain petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

E) FLOW-THROUGH SHARES

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future income tax liability is increased and capital stock is reduced by the estimated tax benefits transferred to shareholders.

F) PER SHARE AMOUNTS

The treasury stock method is used to determine the dilutive effect of stock options. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market rate.

G) USE OF ESTIMATES

The preparation of consolidated financial statements in accordance with accounting principles generally accepted in Canada requires management to make assumptions and estimates that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from estimated amounts as future confirming events occur.

H) INCOME TAXES

Income taxes are recorded using the liability method of tax allocation. Future income taxes are calculated based on temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value using tax rates anticipated to apply in the periods when the temporary differences are expected to reverse.

I) REVENUE RECOGNITION

Revenue associated with the production and sales of crude oil, natural gas and natural gas liquids owned by the Company are recognized when title passes from the Company to its customer.

J) STOCK-BASED COMPENSATION PLAN

The Company has a stock-based compensation plan, which includes stock options and an employee stock savings plan.

Consideration received from employees or directors on the exercise of stock options under the stock option plan is recorded as capital stock. Compensation costs have not been recognized for fixed stock options granted to employees and directors. The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense.

K) DEFERRED FINANCING CHARGES

Financing costs related to the issuance of the senior term notes have been deferred and are amortized over the term of the respective senior term notes on a straight-line basis.

L) FOREIGN CURRENCY TRANSLATION

Long-term debt payable in U.S. dollars is translated into Canadian dollars at the period-end exchange rate, with any resulting adjustment recorded in the consolidated statements of earnings and retained earnings.

M) DIVIDEND POLICY

The Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

3. CHANGES IN ACCOUNTING POLICIES

A) Effective January 1, 2002, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") amended accounting standard with respect to accounting for foreign currency translation. As a result of adopting this amended standard, gains or losses on the translation of long-term debt denominated in U.S. dollars are no longer deferred and amortized over the term of the debt, but are recognized in earnings. The adoption of this amended standard resulted in an unrealized foreign exchange loss of $1.6 million for the fiscal year ended December 31, 2002. This amended standard affects the Company's accounting for its U.S. denominated senior term notes due May 15, 2009 (refer to Note 7).

B) During the fourth quarter of 2001, the Company early adopted the new recommendations of the CICA with respect to accounting for stock-based compensation. The Company has adopted this accounting policy retroactively, without restating the consolidated financial statements of prior periods. Effective January 1, 2001, the Company recorded a reduction in retained earnings of $3.6 million, an increase in accounts payable of $6.2 million and a decrease in future income tax liability of $2.6 million.

C) Effective January 1, 2000, the Company adopted the new recommendations of the CICA with respect to accounting for future income taxes. Under the new recommendations the liability method of tax allocation is used, which is based upon the difference between financial and tax bases of assets and liabilities.

The Company has adopted this change in accounting policy retroactively, without restating the consolidated financial statements of prior periods. As a result, the Company recorded a reduction in retained earnings of $0.4 million, an increase in property and equipment of $68.1 million and an increase in the future income tax liability of $68.5 million, as at January 1, 2000.

D) The CICA approved a new standard for the compilation and disclosure of per share amounts. In 2000, the Company retroactively adopted the new standard. Under this standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of stock options and other dilutive instruments.

Prior period diluted earnings per share and cash flow from operations per share have been restated for this change in accounting policy. If the imputed method had been used to calculate these amounts, the reported amounts would have been for the year ended December 31, 2000, diluted earnings per share – $0.35 and diluted cash flow from operations per share – $1.03.

4. ACQUISITION

Effective July 16, 2001, the Company acquired all of the issued and outstanding shares of Hornet Energy Ltd. ("Hornet"), a public company involved in the exploration, development and production of oil and natural gas primarily in southern Alberta. The acquisition has been accounted for by the purchase method of accounting and the consolidated financial statements include the results of operations from date of acquisition. The fair value of the assets acquired is as follows:

Net assets acquired		
Petroleum and natural gas properties	$	54,276
Future income taxes		(12,236)
		42,040
Working capital deficiency		(1,460)
Long-term debt		(10,320)
Capital lease obligations		(591)
	$	29,669
Consideration		
Cash	$	29,134
Transaction costs		535
	$	29,669

The following table reflects unaudited pro forma combined results of operations of the Company and the above acquisition on the basis that the acquisition had taken place at the beginning of the fiscal years presented:

		2001		2000
Revenue, net of royalties	$	195,593	$	176,777
Net earnings		52,111		39,958
Earnings per share				
Basic	$	0.47	$	0.37
Diluted	$	0.45	$	0.36

5. PROPERTY AND EQUIPMENT

		2002		2001
Exploration and development costs	$	**758,716**	$	635,508
Accumulated depletion		**(158,581)**		(109,091)
		600,135		526,417
Production equipment and processing facilities		**120,537**		88,727
Office equipment		**4,215**		2,808
		124,752		91,535
Accumulated depreciation		**(16,473)**		(11,032)
		108,279		80,503
	$	**708,414**	$	606,920

The Company does not capitalize any portion of its general and administrative expenses. During the year ended December 31, 2002 - nil (2001 – nil; 2000 – $0.7 million) of interest expense associated with certain property acquisitions and processing facilities was capitalized.

Future capital expenditures of $37.5 million (2001 – $33.0 million; 2000 – $37.1 million), as estimated by independent engineers, relating to the development of proven non-producing reserves have been included in costs subject to depletion, and undeveloped properties with a cost at December 31, 2002 of $155.0 million (2001 – $161.0 million; 2000 – $98.8 million), included in exploration and development costs, have not been subject to depletion.

6. CREDIT FACILITIES

		2002		2001
Bank credit facilities	$	**40,000**	$	230,000

As at December 31, 2002, the Company had authorized syndicated senior credit facilities with Canadian financial institutions in the amount of $168 million (2001 – $240 million). The senior credit facilities consist of a $158 million (2001 – $230 million) extendible revolving credit facility and a $10 million (2001 – $10 million) working capital facility. As a result of the Company's US$165 million senior notes issuance, the Company's senior credit facilities were adjusted to $168 million. Advances under the facilities can be drawn in either Canadian or U.S. funds. The facilities bear interest at the lenders' prime lending rate or at the Bankers' Acceptance rate or LIBOR plus a margin based on the ratio of total consolidated debt to cash flow, currently set at 0.625 percent, 1.625 percent and 1.625 percent, respectively. These facilities mature on July 9, 2003.

Effective July 1, 2002, the Company has adopted the recommendations of the CICA's Emerging Issues Committee Abstract 122 concerning the presentation of revolving demand loans. As such, the Company has classified borrowing under its bank credit facilities as a current liability. The bank loan at December 31, 2001 has been restated to conform with current presentation.

The credit facilities are secured by a first fixed and floating charge debenture in the amount of $325 million covering all the Company's assets and undertakings.

7. SENIOR TERM NOTES

		2002		2001
Senior term notes (US$165,000,000)				
Proceeds on issuance	**$**	**259,051**	$	–
Increase due to unrealized foreign exchange loss		**1,583**		–
	$	**260,634**	$	–

On May 8, 2002, the Company completed an offering of US$165 million senior notes bearing interest at 9.9 percent with principal repayable on May 15, 2009. Interest is payable on May 15 and November 15 of each year, beginning on November 15, 2002. The Company used the net proceeds to repay its entire existing bank indebtedness and for general corporate purposes. These senior notes are unsecured and are subordinate to the Company's bank credit facilities.

Concurrent with the closing of the senior notes offering, the Company entered into interest rate swap arrangements with its banking syndicate whereby interest paid by the Company on the US$165 million principal amount will be based upon the 90-day Bankers' Acceptance rate plus 4.85 percent. This arrangement resulted in an effective interest rate of 7.65 percent during the year ended December 31, 2002.

8. CAPITAL LEASES

Certain leases relating to gas processing equipment, having costs in the aggregate of $601 thousand and accumulated depreciation of $93 thousand (2001 – $36 thousand), are classified as capital leases and are included in property and equipment. These capital lease obligations were acquired as part of the Hornet acquisition referred to in Note 4. Each lease contains an option to purchase and has an implicit interest rate of 7.8 percent to 8.8 percent. Excluded from the following future capital lease payment obligations is interest in the amount of $49 thousand.

2003	$	323
2004		36
2005		38
2006		52
		449
Less: current portion, included in accounts payable		323
	$	126

9. SITE RESTORATION AND ABANDONMENTS

At December 31, 2002 total future removal and site restoration costs to be accrued over the life of the remaining proven reserves were estimated, net of recoveries, at $18.8 million (2001 – $8.5 million) of which $2.2 million (2001 – $1.6 million) has been accrued. This estimate is subject to change based on amendments to environmental laws and as new information concerning operations becomes available.

10. CAPITAL STOCK

A) AUTHORIZED

Unlimited number of common shares

Unlimited number of preferred shares, issuable in series

B) ISSUED AND OUTSTANDING

	2002			2001		
	Number of shares		**Amount**	Number of shares		Amount
Common shares						
Balance, beginning of year	**113,105,450**	**$**	**116,572**	108,783,649	$	94,472
Issued for cash, net	**3,085,175**		**9,711**	7,345,604		22,964
Issued for property	**350,000**		**1,225**	241,997		1,285
Issued for cash on exercise of warrants	**–**		**–**	625,616		1,095
Issued for cash on exercise of options	**526,506**		**1,397**	314,584		443
Repurchased for cash	**(796,200)**		**(826)**	(4,206,000)		(3,687)
Balance, end of year	**116,270,931**	**$**	**128,079**	113,105,450	$	116,572

During 2002, common shares issued for cash include 3,085,175 (2001 – 7,345,604) common shares issued on a flow-through basis. Under the terms of the current year flow-through agreements, the Company is required to expend $17.6 million on qualifying oil and natural gas expenditures prior to December 31, 2003. As at December 31, 2002, the Company had not incurred any qualifying expenditures.

During the year, the Company repurchased for cancellation 796,200 common shares at an average price of $3.80 per share (2001 – 4,206,000 shares at an average price of $4.23 per share), pursuant to a normal course issuer bid. The excess of the purchase price over book value has been charged to retained earnings.

C) OUTSTANDING WARRANTS

In 1998, in conjunction with the disposition of certain facilities, the Company issued share purchase warrants to a third party, which entitled the holder to acquire 3,000,000 common shares of the Company. As at December 31, 2002, nil (2001 – nil; 2000 – 1,000,000) warrants were outstanding at an exercise price of $1.75 per share. The warrants were exercisable on the basis of 10,000 warrants for each $250,000 paid to the Company as an incentive fee under the terms of the disposition. During 2001, a total of 625,616 warrants were exercised for gross proceeds of $1.1 million. The remaining warrants were cancelled.

D) SHAREHOLDER RIGHTS PLAN

The Company has a Shareholder Rights Plan to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding. In the event that an acquisition of 20 percent or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder to acquire, at the exercise price of $50.00, such number of common shares as have a market value equal to twice the exercise price.

11. STOCK-BASED COMPENSATION PLANS

The Company has implemented a Stock Option Plan for directors, officers and employees. As of December 31, 2002, there were 14,500,000 common shares reserved for issuance to eligible participants. At December 31, 2002, 10,356,528 (December 31, 2001 – 9,829,334; December 31, 2000 – 6,352,335) options with exercise prices between $0.60 and $4.85 were outstanding and exercisable at various dates to November 12, 2012. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

SHARE APPRECIATION RIGHTS PLAN

At the beginning of 2001, the Company had a share appreciation rights plan of which the financial statement effects of this plan were determined not to be significant to the consolidated financial statements due to the amount vested. During 2001, this plan was cancelled and replaced by a fixed option plan with a variable component.

As a result, a certain number of outstanding fixed options included in the Company's Stock Option Plan have a variable compensation cost to them. As at December 31, 2001, approximately 2.4 million of the outstanding fixed options total of 9.8 million were granted as a result of the aforementioned cancelled share appreciation rights plan. These fixed options, with a variable component, were granted in two tranches: 1.7 million at a fixed option exercise price of $3.02 per option share and 0.7 million at a fixed option exercise price of $4.00 per option share. Attached to these fixed options is a variable compensation component that enables the holder of such fixed option to receive a cash payment from the Company upon exercise of the fixed option. This cash payment varies with each fixed option holder, and is based on the difference between the lesser of the market price of the Company's common shares on the date the fixed option is exercised or the fixed option exercise price, and a stated compensation price for each respective option holder. Under this structure, the maximum variable compensation cash payment is the respective fixed option exercise price.

11. STOCK-BASED COMPENSATION PLANS (CONTINUED)

The aggregate variable cost component relating to these fixed options can vary in amount between a range based on the market value price of the Company's common shares and is limited to a total amount of $3.3 million. The liability related to the variable component of these options amounts to $3.2 million, and is included in accounts payable as at December 31, 2002 (2001 – $3.9 million).

During the year ended December 31, 2002, the Company recorded a compensation expense of $190 thousand related to the outstanding variable component of these options (2001 – $280 thousand recovery).

STOCK OPTIONS

The following tables summarize the information about the stock options as at:

	2002			2001		
Fixed options	**Shares**		**Weighted average exercise price**	Shares		Weighted average exercise price
Outstanding at beginning of year	**9,829,334**	**$**	**2.03**	6,352,335	$	1.08
Granted	**1,669,570**	**$**	**4.00**	3,866,250	$	3.57
Exercised	**(526,506)**	**$**	**2.65**	(314,584)	$	1.41
Cancelled	**(615,870)**	**$**	**3.83**	(74,667)	$	3.63
Outstanding at end of year	**10,356,528**	**$**	**2.21**	9,829,334	$	2.03
Options exercisable at year-end	**7,691,288**	**$**	**1.63**	7,009,889	$	1.42

	Options outstanding			Options exercisable	
Range of exercise prices	Number outstanding at December 31, 2002	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at December 31, 2002	Weighted average exercise price
$0.60 - $1.25	4,350,000	3.93	$ 0.76	4,350,000	$ 0.76
$1.45 - $2.30	1,526,667	6.71	$ 1.90	1,460,000	$ 1.88
$2.98 - $3.50	1,460,199	6.91	$ 3.03	1,135,530	$ 3.02
$3.80 - $4.85	3,019,662	8.83	$ 4.05	745,758	$ 4.04
	10,356,528		$ 2.21	7,691,288	$ 1.63

	Options outstanding			Options exercisable	
Range of exercise prices	Number outstanding at December 31, 2001	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at December 31, 2001	Weighted average exercise price
$0.60 - $1.25	4,380,000	5.17	$ 0.77	4,380,000	$ 0.77
$1.45 - $2.30	1,653,334	7.67	$ 1.87	1,436,667	$ 1.83
$2.98 - $3.50	1,922,900	9.75	$ 3.04	826,899	$ 3.02
$3.80 - $4.30	1,873,100	9.67	$ 4.10	366,323	$ 3.94
	9,829,334		$ 2.03	7,009,889	$ 1.42

CICA Handbook Section 3870, "Stock-based Compensation", establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. The Company has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements. Since all options were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the option grants. Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards consistent with methodology prescribed by Handbook Section 3870, the Company's net earnings and net earnings per share would have been the pro-forma amounts for the periods as indicated on page 56.

11. STOCK-BASED COMPENSATION PLANS (CONTINUED)

	2002	2001	2000
Net earnings			
As reported	$ 18,798	$ 55,636	$ 40,059
Less fair value of stock options	(2,221)	(2,190)	(652)
Pro-forma	$ 16,577	$ 53,446	$ 39,407
Net earnings per common share – basic			
As reported	$ 0.17	$ 0.51	$ 0.37
Pro-forma	$ 0.15	$ 0.49	$ 0.37
Net earnings per common share – diluted			
As reported	$ 0.16	$ 0.48	$ 0.36
Pro-forma	$ 0.14	$ 0.47	$ 0.36

The weighted average fair market value of options granted for the years ended December 31, 2002, 2001 and 2000 are $3.00, $2.52 and $1.61 per option, respectively. The fair value of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions:

	2002	2001	2000
Risk-free interest rate	5.2%	5.4%	5.5%
Estimated hold period prior to exercise (years)	10	10	10
Volatility in the price of the Company's common shares	62.47%	53.75%	52.75%

12. PER SHARE AMOUNTS

Basic earnings per common share and cash flow from operations per common share are computed by dividing earnings and cash flow from operations by the weighted average number of common shares outstanding for the year. Diluted earnings per common share and cash flow from operations per common share are computed by dividing earnings and cash flow from operations by the diluted weighted average number of common shares outstanding for the year. In the calculation of diluted per share amounts, options under the stock option plan are assumed to have been converted or exercised on the later of the beginning of the year and the date granted. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares.

Weighted average shares outstanding (thousands)	2002	2001	2000
Basic	113,428	109,881	106,904
Shares issued pursuant to stock options and warrants	4,572	4,963	3,741
Diluted	118,000	114,844	110,645

In calculating diluted earnings per common share for the year ended December 31, 2002, the Company excluded 2,193,662 options (2001 – 892,500), because the exercise price was greater than the average market price of its common shares in those years.

13. INCOME TAXES

A) PROVISION FOR INCOME TAXES

	2002	2001	2000
Earnings before taxes	**$ 38,993**	$ 79,214	$ 76,656
Expected tax expense at combined federal and provincial rate of	**42.1%**	42.6%	44.6%
	$ 16,424	$ 33,745	$ 34,204
Increase (decrease) resulting from:			
Non-deductible Crown charges	**17,039**	18,570	16,915
Alberta royalty tax credits	**64**	(213)	(291)
Resource allowance	**(14,471)**	(22,984)	(17,486)
Statutory rate change	**(1,340)**	(7,400)	–
Other	**1,051**	530	2,365
Provision for future income taxes	**$ 18,767**	$ 22,248	$ 35,707

B) FUTURE INCOME TAXES

Future income taxes consist of the following temporary differences:

	2002	2001
Property and equipment	**$ 179,739**	$ 157,792
Timing of partnership items	**34,494**	31,088
Alberta royalty tax deduction	**(5,175)**	(5,315)
Non-capital losses	**(1,360)**	(2,162)
Share issue costs and deferred charges	**(1,796)**	(1,542)
Future site restoration	**(709)**	(669)
Future income taxes	**$ 205,193**	$ 179,192

14. FINANCIAL INSTRUMENTS

The Company is exposed to fluctuations in commodity prices, interest rates and Canada/U.S. exchange rates. The Company, when appropriate, utilizes financial instruments to manage its exposure to these risks.

A) COMMODITY PRICE RISK MANAGEMENT

The Company enters into hedge transactions on crude oil and natural gas. The agreements entered into are forward transactions providing the Company with a range of fixed prices on the commodities sold. Oil and gas revenues for the year ended December 31, 2002 include gains of $1.2 million (2001 – $3.7 million gain; 2000 – $7.7 million loss) on these transactions.

The following table outlines the financial agreements in place at December 31, 2002:

	Term	Daily notional volume	Prices received	Unrecognized (gain)/loss ($000s)
Natural gas				
Collar	Nov 02 – Mar 03	23,810 mcf	$4.33/mcf – $7.18/mcf	340
Collar	Apr 03 – Oct 03	23,810 mcf	$4.88/mcf – $6.20/mcf	2,487
Crude oil				
Fixed price contract	Jan 03 – Dec 03	1,000 bbls	US$25.50/bbl	509
Collar	Jan 03 – Dec 03	500 bbls	US$23.50/bbl – US$27.00/bbl	247

The following table outlines the financial agreements that were entered into by the Company, subsequent to December 31, 2002 and are currently outstanding:

	Term	Daily notional volume	Prices received	Unrecognized (gain)/loss ($000s)
Natural gas				
Collar	Apr 03 – Oct 03	9,524 mcf	$5.78/mcf – $7.93/mcf	–
Fixed price contract	Apr 03 – Oct 03	4,762 mcf	$6.85/mcf	–
Crude oil				
Fixed price contract	Feb 03 – Dec 03	500 bbls	US$29.60/bbl	–

B) FOREIGN CURRENCY RISK MANAGEMENT

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and to a large extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to U.S. dollars in order to manage the risk. During the year a gain of $352 thousand was realized and included in revenue (2001 – $nil; 2000 – $353 thousand loss). At December 31, 2002 swaps were in place for the period January 1, 2003 to December 31, 2003. The notional amount swapped thereunder is US$37,250 per day at an average exchange rate of Cdn$1.583 resulting in an unrealized foreign exchange gain of $43.8 thousand.

C) INTEREST RATE RISK MANAGEMENT

The Company's long-term debt has a fixed interest rate and the Company uses interest rate swaps to manage its debt servicing costs. The Company currently has an outstanding interest rate swap on a total of US$165 million of long-term debt. The terms of the swap convert fixed rate interest to floating rate interest which correlates directly to long-term debt, 9.9 percent, semi-annual interest obligations (refer to Note 7). The effect on the Company was a reduction in the effective interest rate to 7.65 percent and an unrealized gain of $15.4 million.

D) CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for oil and gas sales which are generally made to large credit-worthy purchasers, and amounts receivable from joint venture partners which are recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counter-parties to these financial instruments. The Company deals with major institutions and believes these risks are minimal.

E) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The fair values of the Company's financial assets and liabilities that are included in the Company's consolidated balance sheet as at December 31, 2002 approximate their carrying value. The fair value of the senior term notes does not significantly differ from the carrying amount since the estimated interest rates that would be available to the Company at December 31, 2002 approximate the actual interest rate of the senior term notes.

15. CASH FLOW

Changes in non-cash working capital items increased (decreased) cash and cash equivalents as follows:

	2002	2001	2000
Accounts receivable and other	$ 1,312	$ (413)	$ (29,568)
Accounts payable	(1,629)	5,459	15,915
	$ (317)	$ 5,046	$ (13,653)
Operating activities			
Accounts receivable	$ (6,480)	$ (10,704)	$ (18,165)
Accounts payable	1,637	3,438	4,819
	(4,843)	(7,266)	(13,346)
Financing activities			
Accounts receivable	–	–	–
Accounts payable	3,514	–	–
	3,514	–	–
Investing activities			
Accounts receivable	7,792	10,291	(11,403)
Accounts payable	(6,780)	2,021	11,096
	1,012	12,312	(307)
	$ (317)	$ 5,046	$ (13,653)

Cash amounts paid during the year relating to interest expense and capital taxes are as follows:

	2002	2001	2000
Interest paid	$ 15,042	$ 13,054	$ 13,639
Capital taxes paid	$ 1,084	$ 793	$ 470

16. COMMITMENTS AND CONTINGENT LIABILITIES

A) COMMITMENTS

The Company has committed to certain payments under operating leases over the next three years, as follows:

		2003		2004		2005
Equipment	$	1,636	$	769	$	352
Office rental		1,444		1,452		481
	$	3,080	$	2,221	$	833

B) LEGAL PROCEEDINGS

The Company is involved in various legal claims associated with normal operations. These claims, although unresolved at the current time, are minor in nature and are not expected to have a material impact on the financial position or results of operations of the Company.

17. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

RECONCILIATION OF CONSOLIDATED FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States of America ("U.S. GAAP"). Any significant differences in those principles, as they apply to the Company's statements of earnings, balance sheets and statements of cash flow, are as follows:

A) Under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of future or deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10 percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Under Canadian GAAP, the "ceiling test" is calculated without application of a discount factor to future net revenues, but estimated future general and administrative and financing costs are deducted from future net revenue. Prior to January 1, 2001, Canadian GAAP required the test to be performed annually, whereas U.S. GAAP required the ceiling test to be performed at the end of each quarter. Subsequent to January 1, 2001, Canadian GAAP requires the ceiling test to be performed at the end of each quarter. The Company has completed a ceiling test calculation at December 31, 2002, 2001, 2000 and 1999 with no write-down required under either Canadian or U.S. GAAP. At December 31, 1998 the application of the full cost ceiling test under U.S. GAAP would have resulted in a write-down of capitalized costs of $13.8 million after income tax, utilizing commodity prices at December 31, 1998 of $15.33/bbl for crude oil and $2.50/mcf for natural gas. As commodity prices were uncharacteristically low at December 31, 1998 and considering a subsequent strengthening of prices in the first quarter of 1999, U.S. GAAP allows the Company to choose a different measurement date for purposes of calculating the full cost ceiling test. Accordingly, the application of the ceiling test at March 31, 1999 did not result in a write-down, indicating that the capitalized costs were not in fact impaired at year end. The application of the full cost ceiling test under U.S. GAAP for years prior to the year ended December 31, 1998 did not result in a write-down of capitalized costs.

17. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (CONTINUED)

B) Under U.S. GAAP, the provision for future site restoration costs is recorded as a reduction of property and equipment in the amount of $2.2 million at December 31, 2002 (2001 – $1.6 million).

C) Statement of Financial Accounting Standards ("SFAS") 123, "Accounting for Stock-based Compensation", establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by SFAS 123, the Company has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25 ("APB 25"). Since all options were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the option grants. As discussed in Note 3(b), the Company retroactively adopted effective January 1, 2001, the standards of accounting released by the CICA for stock based compensation. These standards are consistent with SFAS 123.

APB 25, as interpreted by the Financial Accounting Standards Board's ("FASB") interpretation 44, also requires recognition of compensation cost with respect to changes in intrinsic value for variable employee stock compensation plans. As a result of the modifications to the terms of employee stock options, the modified options are subject to variable plan accounting, which result in a compensation cost of $4.5 million for the year ended December 31, 2000 for U.S. GAAP purposes.

D) Prior to January 1, 2000, the Company recorded the renouncement of tax deductions resulting from the issuance of flow-though shares by reducing property and equipment and share capital by the estimated cost of the tax deductions renounced.

U.S. GAAP requires that flow-through shares be recorded at their fair value without any adjustment for the renouncement of the tax deductions and any temporary difference resulting from the renouncement must be recognized in the determination of tax expense in the year incurred. U.S. GAAP also requires that the estimated cost of the tax deductions renounced be recorded as a future income tax liability rather than a reduction of property and equipment. Subsequent to January 1, 2000, the Company accounted for the estimated cost of the tax deduction renounced as a future tax liability and hence was consistent with U.S. GAAP. See Note 3(c) for the effect of this accounting policy change on property and equipment and future income taxes in 2000.

The impact of recording flow-through shares at their fair value for the year ended December 31, 2002, was to increase the future income tax provision by $5.4 million (2001 - $8.7 million; 2000 - $4.7 million) and to increase capital stock by a corresponding amount.

E) Statement of Financial Accounting Standards 130, "Comprehensive Income", requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus other comprehensive income. Management believes that it has no other comprehensive income other than as described under Note 17(f).

F) SFAS 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS 137 and SFAS 138, was issued in June 1998 by the FASB. SFAS 133 establishes new accounting and reporting standards for derivative instruments and for hedging activities. This statement requires the Company to measure all derivatives at fair value and to recognize them in the balance sheet as an asset or liability, depending on the Company's rights or obligations under the applicable derivative contract. Changes in the fair value of derivatives will be recorded each quarter in net income or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, depending on the type of hedge transaction. The ineffective portion of all hedges will be recognized in net income. If a derivative does not qualify as a hedging relationship, the derivative is recorded at fair value and changes in its fair value will be reported in net income. Under the current accounting policy for derivatives, only derivatives used in sales and trading activities are recorded on the balance sheet at fair value. The effective date of SFAS 133 for the Company was January 1, 2001.

G) Under U.S. GAAP, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred financing charges. At December 31, 2002 deferred financing charges and senior term notes were reduced by $4.1 million (2001 - $nil).

Derivatives

The Company used forward contracts and options on forward contracts to manage the risk of fluctuations in the market price of natural gas, crude oil and the change in interest rates. At December 31, 2002, the Company had 15 forward contracts in place.

At December 31, 2002, the natural gas and crude oil futures contracts, determined to be derivatives under SFAS 133, are accounted for as cash flow hedges and expire on various dates through December 2003. These contracts are recorded at fair value on the balance sheet as a $3.4 million liability at December 31, 2002 and a $187 thousand asset at December 31, 2001. The effective portion of the change in fair value is recorded in comprehensive income, net of tax. The ineffective portion of the change in fair value is recorded in net income, net of tax and subsequently recognized as a component of revenue on the statement of earnings and retained earnings when the underlying product being hedged is purchased. The effective portion of these commodity contracts is a $1.7 million loss, which is recorded in comprehensive income as at December 31, 2002 (2001 - $123 thousand gain). The ineffective portion of these commodity contracts is a $253 thousand loss, which is recorded in net income as at December 31, 2002 (2001 - $nil).

On May 8, 2002, concurrent with the issue of the senior term notes, the Company entered into three interest-rate swaps, determined to be derivatives under SFAS 133. The swap settlement terms coincide with the interest obligations on the senior term notes, being May 15 and November 15 each year, as do the maturity and expiry date, May 8, 2009. The swaps are determined to be fair value hedges and the terms of the contract allow the Company to use the short cut method in determining the accounting treatment. Using this method, an increase to assets and senior term notes of $15.4 million was recognized at December 31, 2002 (2001 - $nil).

17. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (CONTINUED)

CONSOLIDATED STATEMENTS OF OPERATIONS

The application of U.S. GAAP would have the following effect on net income:

Years ended December 31,		**2002**		2001		2000
Net income for the year, as reported	**$**	**18,798**	$	55,636	$	40,059
Adjustments:						
Compensation costs (c)		**–**				(4,484)
Related income taxes		**–**				2,000
Accounting for income taxes (d)		**(5,402)**		(8,715)		(4,694)
Other income (expense) (f)		**(253)**		–		–
Net income for the year - U.S. GAAP	**$**	**13,143**	$	46,921	$	32,881
Net income per common share – U.S. GAAP						
Basic	**$**	**0.12**	$	0.43	$	0.31
Diluted	**$**	**0.11**	$	0.41	$	0.30
Statement of comprehensive income (e)						
Net income for the year – U.S. GAAP	**$**	**13,143**	$	46,921	$	32,881
Accounting for hedging (f)		**(1,741)**		123		–
Comprehensive income	**$**	**11,402**	$	47,044	$	32,881
Depletion and depreciation expense – U.S. GAAP	**$**	**56,003**	$	50,450	$	41,767
Depletion and depreciation expense – U.S. GAAP per BOE produced	**$**	**7.81**	$	7.69	$	7.04

CONSOLIDATED BALANCE SHEETS

The application of U.S. GAAP would have the following effect on the balance sheets:

	December 31, 2002		
	As reported	Increase (decrease)	U.S. GAAP
Assets			
Property and equipment (b)	$ 708,414	$ (2,245)	$ 706,169
Accounting for hedging (f)	–	15,402	15,402
Deferred financing charges (g)	13,444	(4,060)	9,384
Liabilities			
Site restoration costs (b)	$ 2,245	$ (2,245)	$ –
Accounting for hedging (f)	–	3,446	3,446
Future income taxes (f)	205,193	(1,452)	203,741
Senior term notes (f and g)	260,634	11,342	271,976
Shareholders' equity			
Capital stock (d)	$ 128,079	$ 29,244	$ 157,323
Retained earnings (see schedule on pg. 66)	117,720	(31,238)	86,482

	December 31, 2001		
	As reported	Increase (decrease)	U.S. GAAP
Assets			
Property and equipment (b)	$ 606,920	$ (1,569)	$ 605,351
Accounting for hedging (f)	–	187	187
Liabilities			
Site restoration costs (b)	$ 1,569	$ (1,569)	$ –
Future income taxes (f)	179,192	64	179,256
Shareholders' equity			
Capital stock (d)	$ 116,572	$ 23,843	$ 140,415
Retained earnings (see schedule on pg. 66)	101,288	(23,720)	77,568

17. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (CONTINUED)

December 31,		2002		2001
Retained earnings under Canadian GAAP	$	**117,720**	$	101,288
Flow-through share differences (d)		**(29,244)**		(23,843)
Commodity derivatives (f)		**(1,994)**		123
Retained earnings under U.S. GAAP	$	**86,482**	$	77,568

CONSOLIDATED STATEMENTS OF CASH FLOW

The application of U.S. GAAP would not change the amounts as reported under Canadian GAAP for cash flows provided by (used in) operating, investing or financing activities, except for the following:

(i) Unspent flow-through share proceeds which have been received at year-end. During 2002, the Company received $17.6 million in proceeds from the issuance of flow-through shares of which $17.6 million remained unspent as at December 31, 2002 (2001 - $25.6 million, 2000 - $12.5 million). Accordingly, under U.S. GAAP, these proceeds would be disclosed separately on the balance sheet as restricted cash and would not be treated as cash or cash equivalents for statement of cash flow reporting purposes. The result of this difference would be to disclose an increase in restricted cash as an investing activity and to reduce cash, end of year by $17.6 million at December 31, 2002 (2001 - $25.6 million, 2000 – $12.5 million);

(ii) The consolidated statements of cash flow include, under investing activities, changes in working capital for items not affecting cash, such as accounts payable and accounts receivable, related to the non-cash elements of property and equipment additions. This disclosure is provided in order to disclose the aggregate costs related to such activities and to identify the non-cash component thereof and to arrive at the cash amounts. This presentation is not permitted under U.S. GAAP;

(iii) The consolidated statements of cash flow include, under investing activities, site restoration costs. Under U.S. GAAP these costs would be presented under operating activities;

(iv) The consolidated statements of cash flow contains disclosure relating to cash flow from operations per share amounts. This presentation is not permitted under U.S. GAAP; and

(v) The consolidated statements of cash flow, for the year ended December 31, 2002 would have disclosed a negative ending cash balance of $2.9 million after reflecting the adjustment for restricted cash relating to U.S. GAAP treatment of unspent flow-through share proceeds (2001 - $20.4 million, 2000 - $12.5 million). Under U.S. GAAP, this negative ending cash balance (or bank overdrafts) would be reflected as a financing activity in the consolidated statements of cash flow.

ADDITIONAL U.S. GAAP DISCLOSURE

December 31,	2002	2001
Accounts receivable includes the following:		
Revenue receivable	$ 58,518	$ 37,101
Joint interest receivable	6,485	26,132
Other receivables	15,686	18,768
	$ 80,689	$ 82,001

December 31,	2002	2001
Accounts payable and accrued liabilities includes the following:		
Trade payables	$ 44,701	$ 52,393
Royalties payable	8,209	5,202
Taxes payable	1,902	2,359
Other payables	8,463	4,949
	$ 63,275	$ 64,903

The aggregate capitalized costs of oil and gas activities and costs incurred in oil and gas property acquisitions, development and exploration activities are as follows:

CAPITALIZED COSTS

December 31,	2002	2001
Proven properties	$ 728,218	$ 566,074
Unproven properties:		
Acquisition	101,044	110,764
Exploration	54,205	50,205
Accumulated depletion and depreciation	(175,053)	(120,123)
	$ 708,414	$ 606,920

17. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (CONTINUED)

COSTS INCURRED ON UNPROVEN PROPERTIES

	Dec 31,	Includes costs incurred in				
	2002	2002	2001	2000	1999	Prior years
Acquisition	**$ 101,044**	$ (9,720)	$ 38,455	$ 26,006	$ 17,535	$ 28,768
Exploration	**54,205**	4,000	23,759	17,143	9,303	-
	$ 155,249	$ (5,720)	$ 62,214	$ 43,149	$ 26,838	$ 28,768

COSTS INCURRED

	2002	2001	2000
Acquisition costs (net of disposition)			
Proven properties	**$ 27,157**	$ 30,716	$ 241
Unproven properties	**(9,720)**	38,455	26,006
Development costs			
Development of proven undeveloped reserves	**21,280**	16,088	19,573
Other	**52,971**	27,229	48,582
Exploration costs	**63,462**	75,417	23,992
Total costs incurred	**$ 155,150**	$ 187,905	$ 118,394

Costs are transferred into the depletion base on an ongoing basis as the undeveloped properties are evaluated and proven reserves are established or impairment determined. Pending determination of proven reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate.

December 31,	**2002**	2001
Future income tax liabilities		
Property and equipment	**$ 214,233**	$ 188,880
Future income tax assets		
Other temporary differences	**(5,175)**	(5,315)
Abandonment costs	**(709)**	(669)
Loss carry forward	**(1,360)**	(2,162)
Other	**(3,248)**	(1,478)
Future income taxes	**$ 203,741**	$ 179,256

RECENT ACCOUNTING PRONOUNCEMENTS

In August 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") 143, "Accounting for Asset Retirement Obligations". This Statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS 143 requires an entity to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of a tangible long-lived asset. SFAS 143 also requires the entity to record the contra to the initial obligation as an increase to the carrying amount of the related long-lived asset (i.e., the associated asset retirement costs) and to depreciate that cost over the remaining useful life of the asset. The liability is adjusted at the end of each period to reflect the passage of time (i.e., accretion expense) and changes in the estimated cash flows underlying the initial fair value measurement. Entities are required to adopt SFAS 143 for fiscal years beginning after June 15, 2002. The Company will adopt SFAS 143 on January 1, 2003, and expects it may have a material impact on the consolidated financial statements.

In October 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS 144 supersedes SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of", and certain provisions of APB Opinion 30, "Reporting the Results of Operations, Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions". SFAS 144 establishes standards for long-lived assets to be disposed of, and redefines the valuation and presentation of discontinued operations. SFAS 144 is effective for fiscal years beginning after December 15, 2001, and interim periods within those fiscal years. The adoption of SFAS 144 did not have a material effect on the Company's financial position, results or operations, or cash flows.

In June 2002, the FASB issued SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities". SFAS 146 requires recording costs associated with exit or disposal activities at their fair values when a liability has been incurred. Under previous guidance, certain exit costs were accrued upon management's commitment to an exit plan, which is generally before an actual liability has been incurred. The requirements of SFAS 146 are effective prospectively for exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB issued FASB Interpretation 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 requires that upon issuance of a guarantee, a guarantor must recognize a liability for the fair value of an obligation assumed under a guarantee. FIN 45 also requires additional disclosures by a guarantor in its interim and annual financial statements about the obligations associated with guarantees issued. The recognition provisions of FIN 45 are effective for any guarantees issued or modified after December 31, 2002. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. Management does not expect that the adoption of FIN 45 will have a material effect on the Company's financial position, results of operations or cash flow.

In December 2002, the FASB issued SFAS 148, "Accounting for Stock-Based Compensation – Transition and Disclosure". SFAS 148 amends SFAS 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS 148 is effective for fiscal years beginning after December 15, 2002. The expanded annual disclosure requirements and transition provisions are effective for fiscal years ending after December 15, 2002. The interim disclosure provisions are effective for financial reports containing financial statements for interim periods beginning after December 15, 2002. SFAS 148 has no material impact on the Company's financial position, results of operations, or cash flow, as the Company does not plan to adopt the fair value method of accounting for stock options at the current time. Management has included the required disclosures in Note 11 of the consolidated financial statements.

SUPPLEMENTAL RESERVE INFORMATION (UNAUDITED)

The net proven oil and natural gas reserve estimates as at December 31, 2002, 2001 and 2000 set forth below were prepared in accordance with guidelines established by the Securities and Exchange Commission and accordingly were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the respective year ends were used without any escalation except in those instances where the sale is covered by contract, in which case the applicable contract price is used. Operating costs, royalties and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proven reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present value should not be construed as the current market value of the Company's oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of the reserves are located in Canada.

ESTIMATED QUANTITIES OF RESERVES

	Years ended December 31,					
	2002		2001		2000	
	Crude oil and ngls (mbbls)	**Natural gas (mmcf)**	Crude oil and ngls (mbbls)	Natural gas (mmcf)	Crude oil and ngls (mbbls)	Natural gas (mmcf)
Balance, beginning of year	**9,777**	**262,448**	9,423	223,761	10,682	181,759
Revisions of previous estimates	**529**	**11,712**	313	(3,186)	(2,524)	1,715
Extensions, discoveries and other additions	**1,829**	**58,853**	1,611	63,248	1,399	60,495
Acquisitions of minerals in place	**514**	**18,805**	301	7,412	1,809	8,761
Dispositions of minerals in place	**(84)**	**(5,343)**	(45)	(382)	(180)	(3,930)
Production	**(1,842)**	**(31,974)**	(1,826)	(28,405)	(1,763)	(25,039)
Balance, end of year	**10,723**	**314,501**	9,777	262,448	9,423	223,761
Proven developed reserves						
Balance, beginning of year	**8,938**	**232,319**	8,576	187,969	8,629	156,939
Balance, end of year	**9,723**	**293,836**	8,938	232,319	8,576	187,969

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVEN OIL AND NATURAL GAS RESERVES

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proven Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of the Company's oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proven reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revisions.

Under the Standardized Measure, future cash inflows were estimated by applying year end prices, adjusted for contracts currently in place to deliver production to the estimated future production of year end proven reserves. Future cash inflows were reduced by estimated future production and development costs based on year end costs to determine pre-tax cash inflows. Future taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proven oil and natural gas properties. Tax credits and net operating loss carry forwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

Years ended December 31, (Cdn$000s)	**2002**	2001	2000
Future cash inflows	**$ 2,460,747**	$ 1,270,787	$ 2,524,446
Future production costs	**(507,576)**	(431,127)	(382,540)
Future development costs (1)	**(56,209)**	(41,943)	(41,035)
Future net cash flows	**1,896,962**	797,717	2,100,871
Income taxes	**(733,434)**	(264,960)	(907,123)
Total undiscounted future net cash flows	**1,163,528**	532,757	1,193,748
10% annual discount for estimated timing of cash inflows	**(509,831)**	(215,296)	(483,879)
Standardized measure of discounted future net cash flows	**$ 653,697**	$ 317,461	$ 709,869

(1) The Company estimates that it will incur $11.3 million in 2003, $10.0 million in 2004 and $nil in 2005 to develop proved undeveloped reserves.

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proven oil and natural gas reserves:

Years ended December 31,	**2002**	2001	2000
(Cdn$000s)			
Beginning of year	**$ 317,461**	$ 709,869	$ 271,486
Sales of production, net of production costs	**(126,745)**	(151,724)	(137,110)
Net change in sales prices, net of production costs	**502,652**	(807,804)	783,990
Extensions, discoveries and additions	**198,811**	127,656	116,197
Changes in estimated future development costs	**(58,187)**	(48,528)	(26,630)
Development costs incurred during the period which reduced future development costs	**66,881**	58,982	51,305
Revisions in quantity estimates	**70,721**	(2,099)	88,175
Accretion of discount	**42,348**	111,245	35,497
Purchase of reserves	**55,129**	17,976	87,440
Sales of reserves	**(20,051)**	(1,517)	(7,783)
Net change in income tax	**(234,813)**	389,962	(395,612)
Changes in production rates (timing) and other	**(160,510)**	(86,557)	(157,086)
Standardized measure, end of year	**$ 653,697**	$ 317,461	$ 709,869

BOARD OF DIRECTORS

MEL F. BELICH, Q.C., CHAIRMAN

President, Enbridge International Inc. (energy transportation and distribution company)

Mr. Belich has been one of Compton's directors since 1993 and provides strong business experience, corporate governance guidance and legal perspective. Mr. Belich is Chairman of Compton's Governance and Compensation Committee. Mr. Belich is currently President, Enbridge International Inc. and Group Vice President – International and Corporate Law, Enbridge Inc. He was a senior partner in the law firm Milner Fenerty (now Fraser Milner Casgrain LLP), where he held a series of senior management and counsel positions during his 20 years with that firm. He was appointed Queen's Counsel in 1996.

IRVINE J. KOOP, P. ENG.

Chairman and Chief Executive Officer, IKO Resources Inc.

Mr. Koop has been one of Compton's directors since 1996 and is a professional engineer with extensive experience in major oil and gas and energy companies in senior management positions and directorships. Mr. Koop is Chairman of Compton's Audit, Finance and Risk Committee. Mr. Koop is currently Chairman and Chief Executive Officer, IKO Resources Inc. He was Executive Vice-President and President and Chief Executive Officer, Pipelines and Midstream, of Westcoast Energy Inc. (an energy products and services company recently acquired by Duke Energy Corporation), and was the former President and Chief Executive Officer of Numac Energy (an oil and gas company acquired by Anderson Exploration).

JOHN W. PRESTON

Account Executive, Sun Microsystems of Canada Inc. (computer company)

Mr. Preston has been one of Compton's directors since 1993 and provides strong business experience and special expertise with his knowledge of geophysical software applications. Prior to his current position at Sun Microsystems, he held equivalent management positions with various telecommunications and computer companies.

JEFFREY T. SMITH, P. GEOL.

Independent Retired Petroleum Executive

Mr. Smith has been one of Compton's directors since 1999 and is a professional geologist with extensive experience in public oil and gas companies in various senior management positions and directorships. Mr. Smith is Chairman of Compton's Engineering, Environmental, Health and Safety Committee. He was Chief Operating Officer of Northstar Energy Corporation (an oil and gas company acquired by Devon Energy).

ERNEST G. SAPIEHA, C.A.

President and Chief Executive Officer, Compton Petroleum Corporation

Mr. Sapieha has held his current position at Compton since the Company's inception in 1993 and is a Chartered Accountant. He has more than 20 years of experience in the oil and gas industry in numerous public oil and gas corporations.

CORPORATE INFORMATION

DIRECTORS

M.F. Belich, Q.C. [1] – President, Enbridge International Inc.,
Chairman, Compton Petroleum Corporation

I.J. Koop, P.Eng. [2] – Chairman and C.E.O., IKO Resources Inc.

J.W. Preston – Account Executive, Sun Microsystems

J.T. Smith, P.Geol. [3] – Independent Retired Petroleum Executive

E.G. Sapieha, C.A. – President and C.E.O., Compton Petroleum Corporation

[1] Chairman, Corporate Governance and Compensation Committee
[2] Chairman, Audit, Finance and Risk Committee
[3] Chairman, Engineering, Environmental, Health and Safety Committee

OFFICERS

E.G. Sapieha, C.A. – President and C.E.O.

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M.J. Stodalka, P.Eng. – V.P. Operations

M.R. Junghans, P.Geol. – V.P. Exploration

T.G. Millar, LL.B. – V.P., General Counsel and Corporate Secretary

D.C. Longfield, P.Eng. – V.P. Engineering

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Outtrim Szabo Associates Ltd.

BANKERS
Bank of Montreal
The Bank of Nova Scotia
The Toronto-Dominion Bank

LEGAL COUNSEL
Fraser Milner Casgrain LLP

AUDITORS
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